SYSTEMS ANALYSES OF ADVANCED BRAYTON CYCLES

FOR

HIGH EFFICIENCY ZERO EMISSION PLANTS

TOPICAL REPORT

TASK 1.3: BASELINE IGCC PLANT SYSTEMS STUDY

UPDATE 2

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SUMMARY

Table 1 shows that the systems efficiency, coal (HHV) to power, is 35%. Table 2 summarizes the auxiliary power consumption within the plant.

Thermoflex was used to simulate the power block and Aspen Plus the balance of plant. The overall block flow diagram is presented in Figure A1.3 - 1 and the key unit process flow diagrams are shown in subsequent figures. Stream data are given in Table A1.3-1. Equipment function specifications are provided in Tables A1.3 – 2 through 17.

The overall plant scheme consists of a cryogenic air separation unit supplying 95% purity O_2 to GE type high pressure (HP) total quench gasifiers. The raw gas after scrubbing is treated in a sour shift unit to react the CO with H_2O to form H_2 and CO_2. The gas is further treated to remove Hg in a sulfided activated carbon bed. The syngas is desulfurized and decarbonized in a Selexol acid gas removal unit and the decarbonized syngas after humidification and preheat is fired in GE 7H type steam cooled gas turbines. Intermediate pressure (IP) N_2 from the ASU is also supplied to the combustors of the gas turbines as additional diluent for NOx control. A portion of the air required by the ASU is extracted from the gas turbines.

The plant consists of the following major process units:

- Air Separation Unit (ASU)
- Gasification Unit
- CO Shift / Low Temperature Gas Cooling (LTGC) Unit
- Acid Gas Removal Unit (AGR) Unit
- Fuel Gas Humidification Unit
- Carbon Dioxide Compression / Dehydration Unit.
- Claus Sulfur Recovery / Tail Gas Treating Unit (SRU / TGTU)
- Power Block.

Table 1: Plant Performance Summary

(ISO Ambient Conditions)

Fuel Feed Rate, ST/D (MF)	3,392
MMBtu/hr (HHV)	3,744
Fuel Feed Rate, MT/D (MF)	3,078
GJ/hr (HHV)	3,949
Power Generation, kWe	
Gas Turbine	318,448
Steam Turbine	154,110
Clean Syngas Expander	2,319
Gas Turbine Extraction Air Expander	4,745
Auxiliary Power Consumption, kWe	97,566
Net Plant Output, kWe	382,056
Generation Efficiency (HHV)	
Net Heat Rate, Btu/kWh	9,800
Net Heat Rate, kJ/kWh	10,337
% Fuel to Power	34.83
Raw Water Makeup, m3/kWh	2.68E-03

Table 2: Auxiliary (In-Plant) Power Consumption Summary

	kWe
Coal Handling	401
Coal Milling	802
Coal Slurry Pumps	274
Slag Handling and Dewatering	155
Miscellaneous Syngas Plant Equipment	380
Air Separation Unit Air Compressors	14,769
Air Separation Auxiliaries	1,290
Oxygen Compressor	12,522
Nitrogen Compressor	22,005
CO_2 Compressor	19,677
Tail Gas Recycle Compressor	958
Boiler Feedwater Pumps	4,055
Cooling Tower and Pumps	7,082
Steam Condensate Pump	42
Selexol Acid Gas Removal	9,457
Syngas Humidification	214
Claus Plant AuxilIiaries	100
Gas Turbine Auxiliaries	517
Steam Turbine Auxiliaries	517
General Makeup and Demineralized Water	324
Miscellaneous Balance-of-Plant and Lighting	1,000
Transformer Losses	1,024
Total Auxiliary Power Consumption	97,566

PROCESS DESCRIPTIONS

Air Separation Unit, Gas Turbine Air Extraction and N_2 Preheat

The primary purpose of the ASU is to supply high pressure, high purity O_2 (at a nominal 95 mole %) to the Gasification unit. Figure A1.3 - 2 depicts the main features of this unit. For the purpose of computer simulation, the ASU has been modeled as two separate sections: An elevated pressure (EP) section which provides compressed air to the cold box operating at elevated pressure, and a low pressure (LP) section which provides compressed air to the cold box operating at lower pressure. This ASU set up with an EP and LP section provides a valid approximation for the performance of an ASU providing oxygen and nitrogen to an IGCC facility in which only a fraction of the entire amount of N2 available from the ASU is required at pressure for gas turbine injection. The actual design of the ASU will be determined by the ASU vendor. The EP section produces the N_2 which is sent to the gas turbine. The Sulfur Recovery unit also consumes a small quantity of O_2. O_2 and N_2 in air are separated by means of cryogenic distillation. Approximately half of the N_2 separated from the air leaves the distillation unit at pressure and is compressed and injected into the gas turbines for NOx emissions control as well as providing additional motive fluid.

For both the EP and LP section, ambient air is sent through a filter to remove dust and other particulate matter and then compressed before providing the air to the "cold box." Interstage cooling and after-cooling of the compressor is accomplished with cooling water. For the EP section, air extracted from the gas turbine compressor discharge is also provided to the "cold box" after expansion, heat recovery, and cooling, while a portion of the N_2 stream produced in the cold box is compressed, preheated and provided to the gas turbine to compensate for the mass of air extracted from the gas turbine.

The compressed air is treated to remove moisture, CO_2 and any hydrocarbons present. This air pretreatment system consists of two molecular sieve vessels. The vessels are operated in a staggered cycle: while one vessel is being used to filter the compressed air, the other is regenerated with the waste N_2 stream from the distillation columns. The waste N_2 is heated to the required regeneration temperature with medium pressure (MP) steam. The clean, dry air is liquefied utilizing a combination of chilling, feed/effluent heat exchange, compression and turbo-expansion. The expander may be compressor loaded or generator loaded. A multi-column system separates the liquefied air into a high purity N_2 stream and a high purity O_2 stream. This cold box is modeled as a separator such that the inlet and outlet stream conditions are consistent with data provided by an air separation unit vendor in the past.

The O_2 stream required by the gasifier and the N_2 stream provided to the gas turbine are compressed in multistage intercooled compressors. The N_2 serves the purpose of a thermal diluent in the gas turbine combustor for NOx control and it also increases the motive fluid for expansion. It is preheated to a temperature of 288°C against HP and high temperature boiler feed water (BFW) extracted from the HRSG located in the power block before it is injected into the gas turbine combustor. The resulting cooler HP BFW is pumped back to the power block.

Coal Receiving and Handling Unit

Coal is received at the plant site by unit train. The coal is unloaded from bottom dump cars into an unloading hopper. Vibrating feeders withdraw the coal from these hoppers and place it on receiving conveyors. A belt scale measures the actual conveyor transport rate. After passing through a magnetic separator, the coal is transported to storage pile. Coal is reclaimed from the coal pile and supplied to day bins which supply coal on a continuous basis to the rod mills for the grinding operation. Coal dust recovered by dust collection systems in the coal storage areas is also sent to the grinding mills.

Gasification Unit

The unit consists of the following sub-systems:

- Coal Grinding and Slurry Preparation
- Quench Gasifier and Slag Handling
- Syngas Scrubber
- Vacuum Flash System
- Soot Filtration
- Condensate Stripping
- Wastewater Pretreatment (WWPT)
- Miscellaneous Supporting Facilities

Figure A1.3 - 3 depicts the main features of this unit along with the coal grinding / slurry preparation. Slurrying water and additives are added to the grinding mill with a feed ratio controller to control the viscosity and produce the desired slurry concentration. This unit is modeled as a mixer to combine the coal with the water and a heater to model the heat added by the milling process. The coal slurry is pumped from a slurry holding tank to the gasifiers where it reacts with the 95% purity O_2. In this arrangement, the reaction chamber effluent is cooled by direct contact with water. The heat carried away by the raw syngas from the gasifier is ultimately recovered as medium pressure (MP) and low pressure (LP) steam downstream in the gas cooling unit.

A quench gasifier consists of a reaction chamber located above a quench chamber. The gasifier is a refractory-lined vessel capable of withstanding high temperature and pressure. The coal slurry and O_2 are fed via a feed injector mounted on top of the gasifier. The injector is cooled by circulating water in a closed-loop injector cooling water system. The coal and O_2 react in the reaction chamber and under conditions of partial oxidation to produce a syngas, which consists primarily of H_2 and CO with lesser amounts of H_2O vapor, CO_2, H_2S, CH_4, and N_2. Traces of COS, HCl and NH_3 are also formed. A portion of the ash, which was present in the coal, and a portion of the unconverted carbon in the gasifier form a liquid melt called slag.

The hot syngas and slag flow downward from the reaction chamber into the quench chamber via a dip tube. The syngas and the slag are cooled by quench water at the bottom of the dip tube. The slag solidifies and is fractured by contact with the water.

The syngas exiting the quench chamber along with particulates which are predominantly carbon, is fed to the syngas scrubber. Syngas exits the top of the syngas scrubber and flows to the CO Shift unit and gas cooling unit. The scrubber removes the particulates and the HCl.

CO Shift / Low Temperature Gas Cooling Unit

The purpose of this unit is to convert most of the CO in the syngas to H_2 by means of the water gas shift reaction:

$$CO + H_2O \longleftrightarrow H_2 + CO_2$$

This conversion step is crucial to the overall carbon capture of the IGCC plant.

The small amount of COS in the raw syngas is also converted into H_2S via the following hydrolysis reaction:

$$COS + H_2O \longleftrightarrow H_2S + CO_2$$

Ammonia in the feed passes through the shift reactor unchanged and will not affect the catalyst performance. On the other hand, HCN will be hydrogenated to CH_4 and N_2. The raw syngas from the Syngas Scrubber has sufficient water vapor to support the water gas shift reaction. Therefore, additional steam injection at the shift reactor is not required.

The heat evolved by the highly exothermic shift reaction is used to generate high and intermediate pressure steam as well as preheat the reactor feed. The remaining sensible heat is further recovered by generating steam at lower pressures and by heating several process streams to cool the shifted syngas down to a level suitable for the Acid Gas Removal unit. Thus the proper design of this section is one of the key factors in determining the overall energy efficiency of the Near Zero Emission plant.

As depicted in Figure A1.3 - 4, scrubbed syngas from gasification is preheated in a feed/effluent exchanger before entering the first shift reactor (the reactor inlet temperature is maintained at start-of-run and at end-of-run by manipulating the scrubbed syngas bypass around the feed/effluent exchanger). The temperatures are set to limit the temperature rise of the syngas as it flows through the first shift reactor. An electric heater is utilized for startup.

The hot shifted syngas exiting this reactor is cooled first in two separate exchangers while producing HP steam (2575 psia) and IP steam (445 psia) and then in the feed/effluent exchanger. The syngas then enters the second shift reactor for additional conversion of the CO. The effluent from the second reactor is then successively cooled by generating steam in the first series of exchangers: the intermediate pressure (IP) steam generator (445 psia), the MP steam generator (120 psia) and then the shifted gas is used to heat up the circulating water streams from the fuel gas humidifier. The outlet temperature of the MP steam generator is set to support the clean syngas humidification processes. The water condensed out from the shifted gas is removed and collected in a process condensate return drum for recycle to the scrubber.

Next as depicted in Figure A1.3 - 5, the shifted gas is further cooled by heating the cold vacuum condensate from the surface condenser of the steam turbine. The shifted gas temperature then flows through a mercury removal bed where 95% of the mercury is captured. Arsenic, Cadmium and Selenium are also expected to be captured by this bed. The bed consists of sulfided activated carbon. The shifted gas is preheated upstream of the carbon bed using MP steam to avoid condensation within the bed.

The shifted gas exiting the mercury removal bed is finally cooled by cooling water and routed to the Acid Gas Removal unit. Condensed water collected in this second series of exchangers is sent to the NH_3 stripper and is then recycle to the particulate scrubber after combining with demineralized deaerated makeup provided by the BFW pump located in the power block.

Acid Gas Removal Unit (Selexol®)

The AGR unit is modeled as a separator such that the component recoveries, the inlet and outlet stream conditions and the utility requirements are consistent with data provided by UOP previously for a study conducted by UCIrvine for the DOE under Award No. DE-FC26-00NT40845. The unit is depicted in Figure A1.3 - 6 where the Untreated Feed Gas enters the unit battery limits and is combined with a stream of concentrated CO_2 which has been stripped from the solvent in the solvent regeneration section as well as hydrogenated, compressed tail gas recycled from the Claus Sulfur Recovery / Tail Gas Recycle unit. This combined stream is sent to the H_2S Absorber, where it contacts cold, loaded solvent. In the H_2S absorber, H_2S, COS, some CO_2 and low levels of other gases such as H_2, are transferred from the gas phase to the liquid phase. The treated gas exits the H_2S absorber and is then sent to the CO_2 absorber. The flow of the solvent exiting the H_2S absorber is described below.

In the CO_2 absorber, the gas contacts chilled, flash-regenerated solvent. Co-absorbed H_2 recovered in the flash process is recompressed, cooled and recycled to the CO_2 absorber. In the CO_2 absorber, CO_2 and low levels of other gases are transferred from the gas phase to the liquid phase. The Treated Syngas exits the CO_2 absorber. The Treated Syngas is sent out of the Selexol unit battery limits to the Humidification unit. The flow of the solvent exiting the CO_2 absorber is described below.

The solvent exiting the H_2S absorber is termed rich solvent, as it contains a significant amount of H_2S, some CO_2 and other gases. The rich solvent exits the H_2S absorber and is pumped through a heat exchanger where its temperature is increased by heat exchange with the lean solvent from the stripper. A portion of the CO_2, CO, H_2 and other gases are selectively stripped from the rich solvent. This stream is mixed with the feed gas, as described above.

The rich solvent is sent to the stripper where the solvent is regenerated and the acid gases are transferred to the gas phase. The acid gases from the stripper are cooled and the condensate is removed. The acid gases are sent out of the Selexol unit battery limits to the Claus Sulfur Recovery Unit. The lean solvent exiting the bottom of the stripper is used to heat rich solvent as described above. The temperature of the lean solvent is further reduced and the lean solvent is then sent to the top of the CO_2 absorber.

The solvent exiting the CO_2 absorber is termed loaded solvent and contains some H_2 and other product gases, but only trace amounts of H_2S. The loaded solvent is flashed and H_2 and other gases are transferred to the gas phase. These gases are separated from any condensate, compressed and are sent back to the CO_2 absorber. The solvent is further regenerated by decreasing its pressure in a series of flash drums. These flash drums are termed the HP, IP and LP Flash Drums. In these drums, large amounts of the absorbed gases, primarily CO_2, are transferred from the liquid phase to the gas phase. The evolved gas exits its respective drum and exits the unit battery limits and are supplied to the CO_2 Compression/Dehydration unit.

The flash-regenerated solvent is chilled and sent back to the CO_2 Absorber. The pressure levels in the HP, IP, and LP Flash Drums are set to match the expected inlet pressures of various stages of a multi-stage compressor.

Syngas Humidification Unit

One of the primary purposes of this humidification unit is to dilute the syngas to the gas turbines with moisture to meet the specification of no more than 65 mole% of H_2 as stipulated by GE for their 7FB gas turbines. This same specification is assumed for the H technology gas turbine. The moisture acts as a thermal diluent in the combustor of the gas turbine and thus reduces the NOx formation. In addition, it increases the motive fluid for expansion in the gas turbine and thus the humidification operation provides a means for efficient recovery of low temperature waste heat in the plant. As depicted in Figure A1.3 - 7, fuel gas from the Acid Gas Removal unit is humidified in a packed column where it is contacted with circulating water in a counter-current manner. The circulating water is heated by shifted syngas in the low temperature gas cooling section. The makeup water to the humidifier is provided by IP BFW that is extracted from the deaerator in the power block. The required amount of moisture can be controlled by resetting the recirculating water flow controller, based on the measurements of the H_2 content, flow rate, temperature and pressure of the feed gas, as well as the temperature and pressure of the humidified syngas. Blowdown from the humidifier to avoid solids buildup within the column is equivalent to 0.5% of the water evaporated in the column. The blowdown is routed to the primary wastewater treating unit. The humidified fuel gas is heated to a temperature of 288°C using high temperature HP BFW extracted from the HRSG. The resulting cooler HP BFW is pumped back to the power block.

CO_2 Compression / Dehydration Unit

As depicted in Figure A1.3 - 8, this unit receives CO_2 product streams from the Acid Gas Removal unit and raises its pressure. The CO_2 compression system is designed to raise the pressure of the CO_2 to a level just above the critical pressure. The CO_2 is then pumped as a supercritical fluid. Inter-stage cooling is effected with cooling water. The discharge of the last stage is cooled and any water vapor in the compressed CO_2 stream is removed by a dehydration unit (utilizing glycerol as the drying agent) and then pumped up to the pipeline pressure before it leaves the plant battery limits. Any condensate collected in the compression process is routed to the solvent flash drum in the Acid Gas Removal unit.

Sulfur Recovery / Tail Gas Treating Unit

This combined unit is depicted in Figures A1.3 - 9, 10 and 11. The purpose of the unit is to convert sulfur compounds in the acid and sour gas streams to elemental sulfur using the Claus process. Ammonia present in the sour gas streams is converted into N_2 and H_2O by oxidation. Any entrained liquid in the acid gas from the AGR unit is separated and sent to the WWPT NH_3 stripper feed drum.

The condensate stripper off gas is fed to a Knockout (KO) drum for removal of any entrained liquid. Liquid is evacuated from the drum and is also sent to the WWPT NH_3 stripper feed drum. A portion of the gas from the acid gas drum is combined with the overhead from the Sour Water Stripper (SWS) drum and fed to the main burner. Fuel gas and LP steam (both normally not required) are also provided to the burner to assist in the combustion of NH_3. The sour gas streams are partially oxidized with O_2 from the Air Separation Unit according to the Claus reaction scheme as shown below:

$$H_2S + 3/2O_2 \leftrightarrow SO_2 + H_2O$$

$$2H_2S + SO_2 \leftrightarrow 3S + 2H_2O$$

$$2H_2S + O_2 \leftrightarrow 2S + 2H_2O \text{ (overall reaction)}$$

Hydrogen sulfide also dissociates at high temperatures, forming H_2 and elemental sulfur as shown below:

$$2H_2S \leftrightarrow 2H_2 + S_2$$

The bulk of the O_2 to the burner is controlled as a "main" stream of O_2 with a smaller, parallel O_2 stream for "trim control" and inputs to the combustion controllers include flow rates of the acid gases and H_2S/SO_2 concentration in the tail gas.

The temperature of the burner is maintained at level required for complete thermal decomposition of the NH_3 into N_2 and H_2O vapor as shown below:

$$2NH_3 + 3/2O_2 \leftrightarrow N_2 + 3H_2O$$

The undesirable NO formation may result if an excess of O_2 is present; therefore, precise monitoring and control of the O_2 stream is necessary.

The stoichiometry of the Claus reaction scheme dictates that only one-third of the H_2S should be combusted with O_2 to generate the required SO_2 for the Claus reaction. Any excess O_2 will lead to a stoichiometric imbalance of H_2S and SO_2, resulting in lower sulfur recovery.

The effluent from the main burner is combined with the remaining portion of the acid gas feed in the reaction furnace. The gas is then cooled by producing HP and IP Steam in the waste heat boiler. Elemental sulfur in the cooled gas is condensed by producing LP steam. The temperature of the cooled gas (which determines the level of steam produced) is set so that almost all the elemental sulfur is condensed; however, it is set high enough to avoid water condensation and sulfur viscosity issues. The condensed sulfur is separated from the gas in a coalescer section that is integral in the exchanger and is drained by gravity to the sulfur pit.

Because thermodynamic equilibrium limits the extent of conversion that can be achieved in the reaction furnace, two additional catalytic beds in series are supplied to recover the required overall sulfur. To allow for the sulfur conversion to proceed further in each subsequent bed, the elemental sulfur produced is condensed and removed from the gas stream.

The effluent gas from the No. 1 Condenser is heated in the No. 1 Reheater with HP steam to avoid condensation of sulfur as the conversion reaction proceeds in the catalyst. The outlet temperature of the gas from the reheater is controlled by varying the HP steam rate. The heated acid gas is routed to the No. 1 Converter where residual H_2S and SO_2 react over catalyst to form elemental sulfur and water in the vapor phase. As the Claus reaction is exothermic, a temperature rise develops across the catalyst bed. As in the previous stage, the elemental sulfur in the gas is condensed in the No. 2 Condenser by producing LP steam. The sulfur condensed in the exchanger is drained by gravity to the sulfur pit.

The last stage of conversion again heats the acid gas in the No. 2 Reheater with IP steam. The outlet temperature of the gas from the reheater is maintained by adjusting the IP steam rate. The heated acid gas is routed to the No. 2 Converter where residual H_2S and SO_2 react over catalyst to form elemental sulfur and water in the vapor phase. The No. 1 and 2 converters are installed in one vessel with a partition separating the catalyst beds. The elemental sulfur in the gas is condensed in the No. 3 Condenser by cooling water. The sulfur condensed in the exchanger is drained by gravity to the sulfur pit.

Air is swept across the sulfur pit and gases released from the molten sulfur in the sulfur pit are removed by the sulfur pit vent ejector using MP steam as a motive fluid and recycled to the reactor furnace. The molten sulfur is pumped to the Degassing and Granulation system.

The effluent gas from the last condenser, called tail gas, still contains small amounts of sulfur dioxide and elemental sulfur compounds and is routed to the Tail Gas Treating section of the unit where any unreacted sulfur dioxide, carbonyl sulfide (COS) and elemental sulfur vapor in the tail gas is converted to H_2S by hydrogenation.

The tail gas is heated in the Reactor Feed Heater with HP steam. The inlet temperature to the hydrogenation reactor is controlled by adjusting the HP steam rate. An analyzer on the tail gas measures the H_2 content of the stream and, if required, treated fuel gas from the Acid Gas Removal unit is added to the reactor feed. The heated tail gas is hydrogenated where sulfur compounds are reduced at elevated temperature via the following reactions:

$$SO_2 + 3H_2 \leftrightarrow H_2S + 2H_2O$$

$$COS + H_2O \leftrightarrow CO_2 + H_2S$$

$$S_6 + 6H_2 \leftrightarrow 6H_2S$$

$$S_8 + 8H_2 \leftrightarrow 8H_2S$$

In addition, the following shift reaction occurs:

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

The effluent from the reactor is cooled by producing LP steam. The partially cooled gas is then further cooled in a contact condenser. The gas enters the condenser below the bottom trays and is contacted with caustic so that any sulfur dioxide remaining in the gas is captured. The column bottoms is recycled in a circulating loop and spent caustic is periodically removed from the loop and routed to the effluent bio-treatment unit.

The scrubbed gas then flows up the condenser for direct quenching with water. The water is removed from the chimney tray in the middle of the condenser and cooled in an air cooler followed by a trim cooler with cooling water. If required, sour water is removed from the system to maintain the water balance (flow rate is varied to control the liquid level on the chimney tray). A portion of the water from the cooling loop may also be diverted to the lower section of the condenser to maintain the liquid level in the bottom of the column. The contact condenser overhead gas is sent to the recycle compressor suction drum to remove entrained liquid. The compressed tail gas is recycled back to the Acid Gas Removal unit.

Power Block

The process scheme for the combined-cycle power block consists of a gas turbine supporting a three-pressure steam turbine. The interface between the HRSG and the steam turbine also includes a reheat steam loop. This configuration has been demonstrated in the power industry to be an economical modular design. The process flow diagram for this unit is depicted in Figure A1.3-12. The overall integration of the steam system between the Power Block and the balance of the IGCC plant is shown on the Steam Balance Diagram, Figure A1.3-13.

The power block consists of the following major systems:

- Gas Turbine
- Heat Recovery Steam Generator (HRSG)
- Steam Turbine and the associated Vacuum Condensate System
- Integral Deaerator
- Blowdown System
- Miscellaneous Supporting Facilities:

- boiler chemical injection
- demineralized water package.

The gas turbine selected for this study is a steam cooled H technology machine. The performance of the gas turbine on the decarbonized syngas was developed utilizing Thermoflex. A model was set up in Thermoflex utilizing published performance by General Electric (GE) for their 7H gas turbine on natural gas and then this model was "operated" in off-design mode to obtain an estimate of its performance on syngas while limiting the 1st stage stator surface temperatures at the same value as that for the natural gas case. This resulted in a decrease in the firing temperature of the gas turbine: from1428°C (2602°F) on natural gas to 1392°C (2538°F) on the syngas. This machine while operating on the syngas was estimated to generate 317.7 MWe. It was assumed that for this machine, the same relative increase in power output going from natural gas operation to syngas operation as the GE 7FA+e gas turbine may be obtained. Figures A1.3 -14 and 15 show the gas turbine cycle diagram for the syngas case and the natural gas case. The cooling steam inlet and outlet volumetric flow rates (and thus the velocities) are essentially the same for the two cases.

Ambient air is drawn into the gas turbine air compressor via a filter to remove air-borne particulates, especially those that are larger than 10 microns. The humidified fuel gas and compressed air are mixed and combusted in the turbine. The preheated nitrogen is injected into the turbine through separate nozzles for NOx control. With the ISO inlet air conditions of 1.01 bara at 15°C and 60% relative humidity, the gas turbine exhaust temperature is 581.7°C.

The Baseline Case does not have any additional NOx abatement control such as an SCR. As a reference GE guarantees 15 ppmvd (15% O_2 basis) on syngas with moisture and nitrogen dilution to the same level as in the baseline case for their "F" technology gas turbines. A sensitivity case has been developed to reduce the NOx to 3 ppmvd (15% O2 basis) utilizing an SCR. The performance for this case is included in this report.

The hot gas turbine exhaust flows through a customized Heat Recovery Steam Generator (HRSG). The HRSG consists basically of the following sub-systems:

- LP steam
- IP steam
- HP steam
- Reheat steam

In addition to these sub-systems, the HRSG is integrated with the rest of the IGCC plant. The HRSG has its own stack, which is equipped with a continuous emissions monitoring system (CEMS).

<u>LP Steam System</u>

Low temperature heat is recovered from the syngas generation / processing units (Process) by heating the vacuum cold condensate from the surface condenser + makeup BFW. The makeup BFW is sprayed directly into the surface condenser and the combined stream of the cold vacuum condensate + makeup is drawn from the Surface Condenser (51-CO-100) by the Vacuum Condensate Pump (51-PU-101A/B) and is sent to the vacuum condensate heaters in the Low

Temperature Gas Cooling Unit and Black Water Flash section of the Gasification Unit to recover the low temperature heat. The hot Vacuum Condensate is further heated in the LP Economizer in the HRSG.

The hot vacuum condensate is combined with LP Condensate returning from the Gasification Unit and is supplied as BFW to the LP Steam Drum (51-VE-103) in the HRSG. The saturated steam from the LP Steam Drum is mixed with the saturated LP steam produced in the Process units. The combined flow is sent through the LP Superheater coils in the HRSG and then is fed to the LP section of the Steam Turbine.

The LP Feed Water Booster Pump (51-PU-105) sends heated BFW from the LP steam drum to the Process users in the Syngas plant.

<u>BFW Pump</u>

The main BFW pump (51-PU-103) of the HRSG supplies both IP and HP BFW to the IP and HP steam systems as well as makeup to the CO Shift/LTGC unit. It is a multistage centrifugal pump, with intermediate bleeds to support the IP steam system and supply the makeup. The discharge pressure of the BFW pump is dictated by the design conditions set at the inlet of the steam turbine.

<u>IP Steam System</u>

The IP BFW is taken from a bleed off of the main BFW Feed pump. The makeup water for the syngas humidifier is taken from the IP bleed before the economizer. The remaining IP boiler feed water flows through the IP Economizer in the HRSG. A portion of the preheated IP BFW is routed to the IP Steam Generators in the CO Shift/LTGC unit and the Sulfur Recovery Unit and the rest is fed to the IP Steam drum. Saturated IP steam generated in the IP steam drum mixes with surplus IP steam from other process units and merges with the reheat steam system.

<u>HP Steam System</u>

The discharge from the main BFW Feed pump is mixed with the HP boiler feed water returning from the Fuel Gas and Nitrogen heaters before it flows through two HP Economizers in the HRSG. The HP BFW Circulating (51-PU-104) pump sends part of the preheated HP boiler feed water exiting the first HP Economizer to the Fuel Gas and Nitrogen heaters.

A portion of the preheated HP BFW is routed to the HP Steam Generator in the CO Shift/LTGC unit and the HP Waste Heat Boiler in the Sulfur Recovery Unit and the remainder is fed to the HP Steam drum. Saturated HP steam generated in the HP steam drum mixes with surplus HP steam from other process units and then is superheated in HP Superheater coils within the HRSG to reach a temperature of 569°C. The superheated HP steam from the HRSG is sent to the inlet of the steam turbine.

A small portion of the main BFW Feed pump discharge is used as attemperator water for the control of the temperature of the superheated steam.

Reheat Steam System

To improve the efficiency of the combined-cycle, the exit steam from the HP section of the steam turbine is returned to the HRSG to raise its temperature by absorbing additional heat. This reheated steam is combined with the IP steam from the HRSG, superheated to the same temperature as the HP steam, 569°C, and then is fed to the inlet of the IP section of the steam turbine.

Gas Turbine Cooling

The 1st and 2nd stages of the gas turbine stator and rotating blades are cooled with steam taken from the HP steam turbine exhaust. The steam returning from this closed circuit cooling of the gas turbine is mixed with the IP steam before it enters the reheater coils in the HRSG.

Deaerator

An integrated LP steam drum/deaerator is provided in the HRSG. This eliminates the need for an external deaerator.

The deaerator removes any dissolved gases such as O_2 and CO_2 in the feed water by using LP steam in the steam drum as the stripping medium.

The pressure in the LP Steam Drum is controlled by varying the amount of steam vented with the dissolved gases.

Blowdown System

The steam drums of the HRSG are continuously purged to control the amount of built-up of dissolved solids. The continuous blowdown is cascaded from the HP steam drum to the IP steam drum. The blowdown is then drawn from the IP steam drum and routed to the Continuous Blowdown drum (51-VE-104). Flash steam in the Continuous Blowdown drum is sent to the LP steam drum and the saturated water is letdown into the Intermittent Blowdown drum (51-VE-105). Whenever required, blowdown from each steam drum in the HRSG system can be routed directly to the Intermittent Blowdown drum. Flash steam from the Intermittent Blowdown drum is vented to atmosphere and the liquid collected in Blowdown Sump.

Steam Turbine

The inlet pressure of the HP section of the steam turbine is set at 166.5 bara. The exhaust from the LP section is set at a vacuum of 0.044 bara. The surface condenser uses circulating cooling water from the cooling towers as the cooling medium while the makeup water for the steam system is added to the well of the condenser.

Demineralized Water System

Demineralized water system consists of mixed-bed exchangers, one in operation and one in stand-by, filled with cation/anion resins, with internal-type regeneration. The package includes facilities for resin bed regeneration, chemical storage and neutralization basin.

General Facilities

The following is a listing of the various necessary support and general facilities that are required for a stand-alone plant. Any utility requirements by these facilities are accounted for in developing the plant performances.

- Natural gas supply – for start-up
- Cooling water system – includes mechanical draft cooling towers and the cooling water supply pumps
- Potable water system
- General makeup water supply system
- Oily water separator - oily water from all process units is collected in the oily water sump, which separates the oil from the water by a corrugated plate interceptor (oil/water separator). Contaminated storm water is also sent to the oily water sump for treatment.
- Drains and blowdowns
- Fire protection and monitoring systems – consist of general firewater system and specialized system for chemical fire protection
- Plant and instrument air system
- Wastewater treatment system – process wastewater is collected for treatment and the treated water is discharged from the plant. A sanitary wastewater treating unit is included in this system
- Flare – the flare system consists of collection headers for the process unit relief gases and a system of knockout drums prior to safe disposal in an elevated flare. A separate flare system is provided for the Sulfur Recovery unit.
- Miscellaneous materials (e.g. slag, fine slag, sulfur) handling (unloading and loading facilities)
- In-plant electric power distribution
- Uninterruptible power supply
- Generator step-up transformers
- Distributed control system
- Continuous emissions monitoring
- Process analyzers
- Hazardous gas detection system
- Communications
- Laboratory for inspection, certification and process control
- Maintenance, warehouse and administration facility
- Other supporting facilities (e.g. interconnecting piping; rail spur for construction materials access; roads, paving, parking, fencing and lighting; heating, ventilation and air conditioning systems).

The overall plant water balance is presented in Figure A1.3-16.

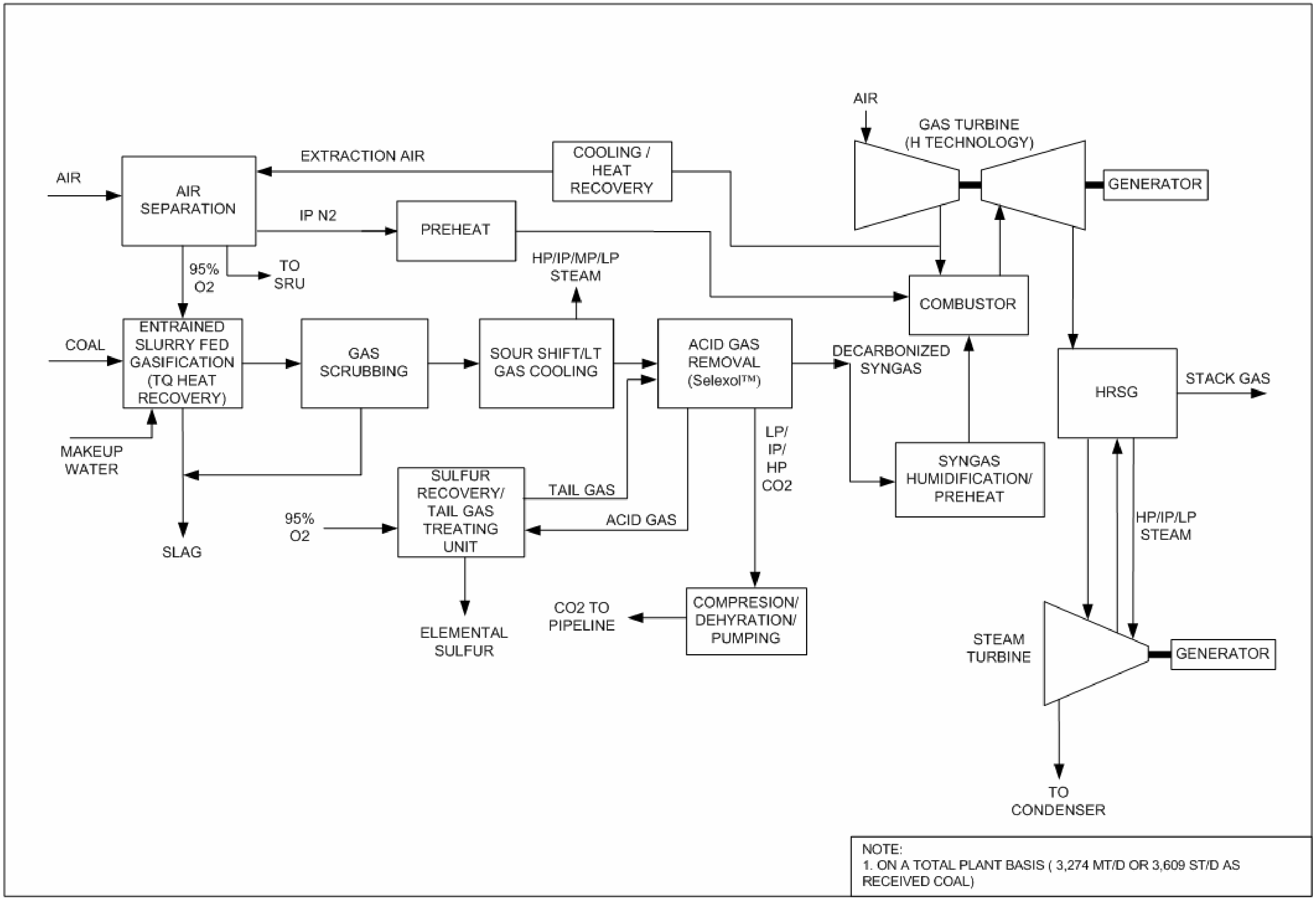

Figure A1.3 - 1: Overall Block Flow Diagram – Baseline Case IGCC with CO_2 Capture

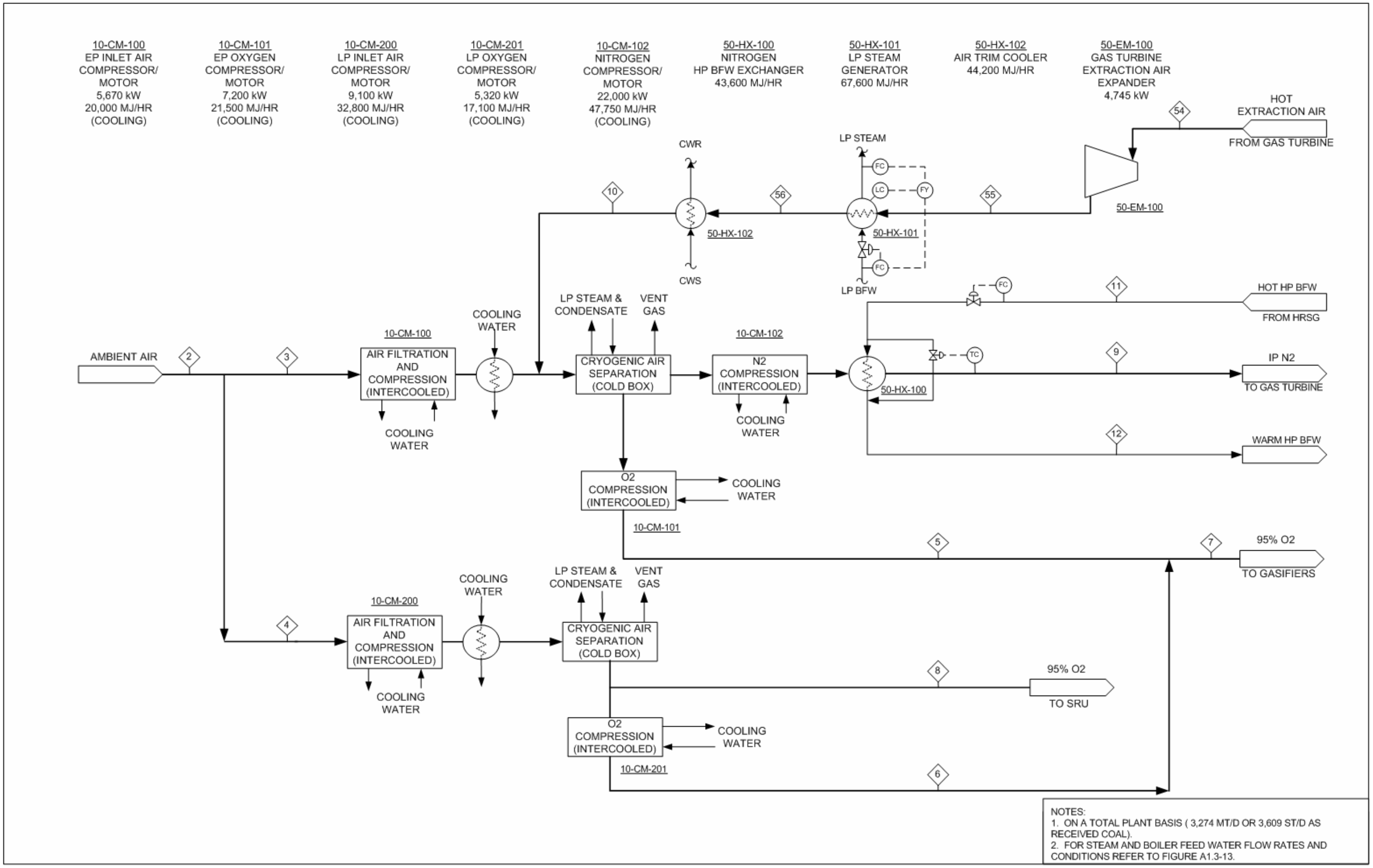

Figure A1.3 - 2: Block Flow Diagram - Air Separation Unit, Gas Turbine Air Extraction and N_2 Preheat

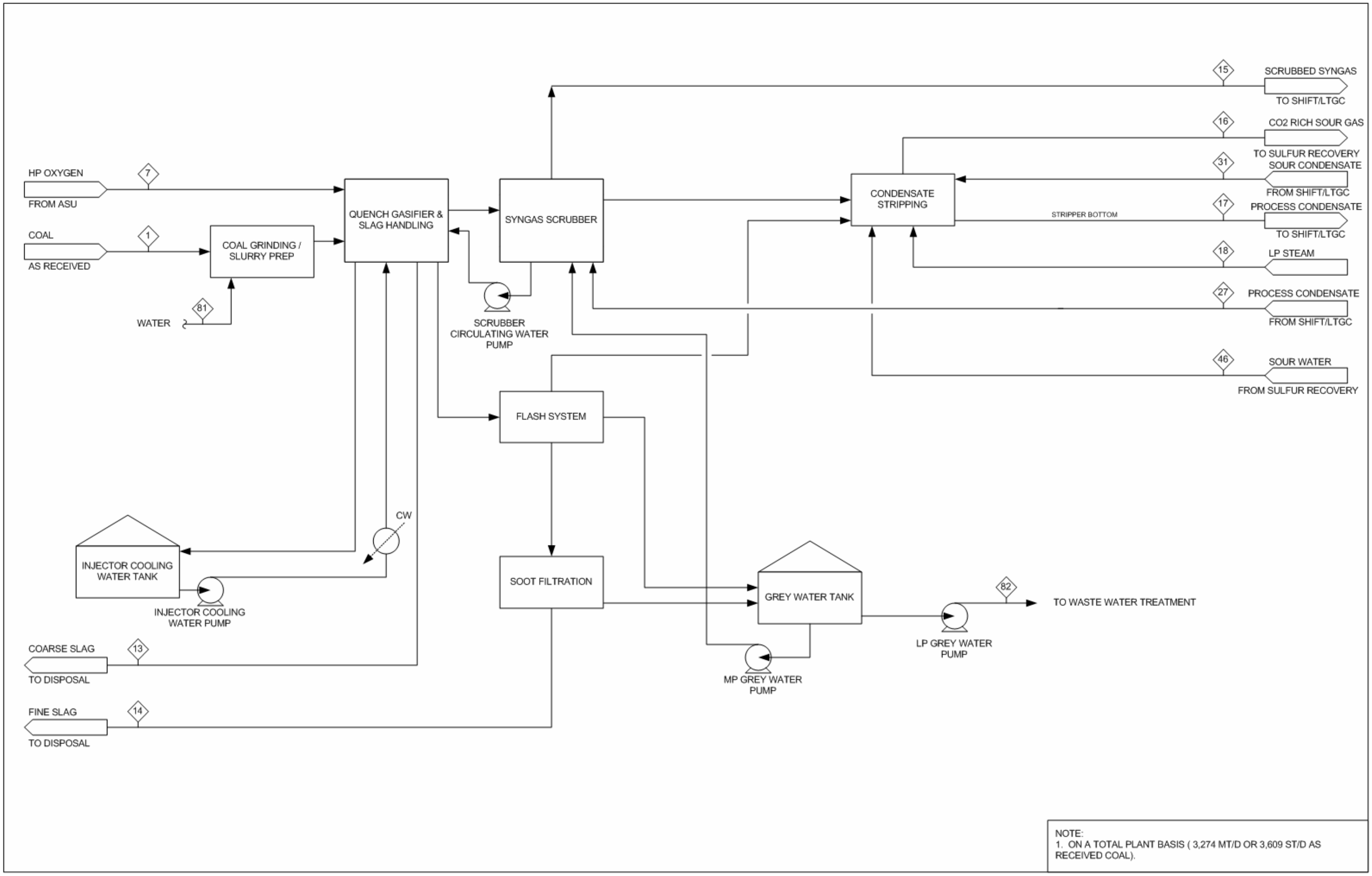

Figure A1.3 - 3: Block Flow Diagram - Gasification Unit and Coal Slurry Preparation

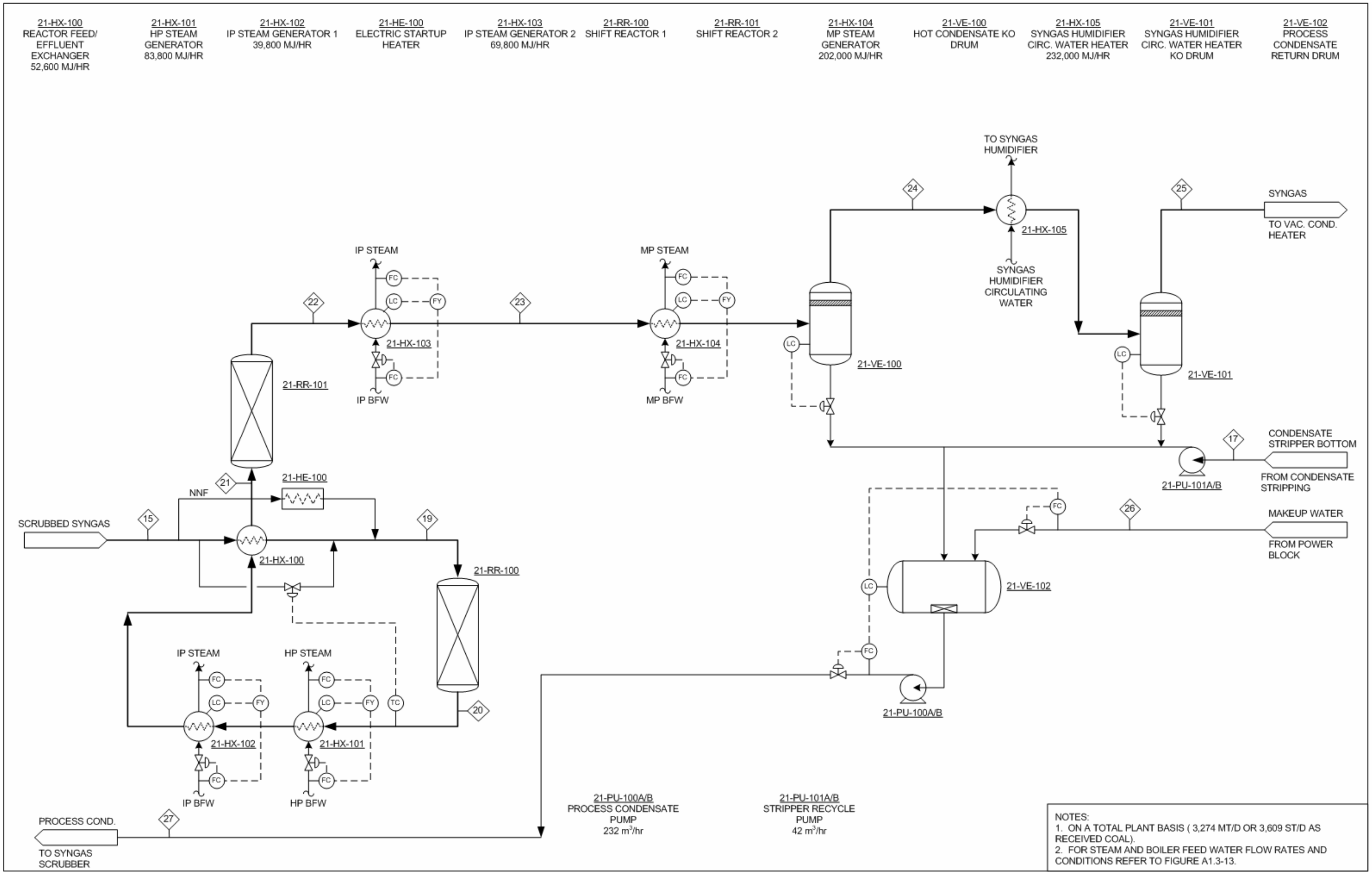

Figure A1.3 - 4: Process Flow Diagram - CO Shift / Low Temperature Gas Cooling Unit

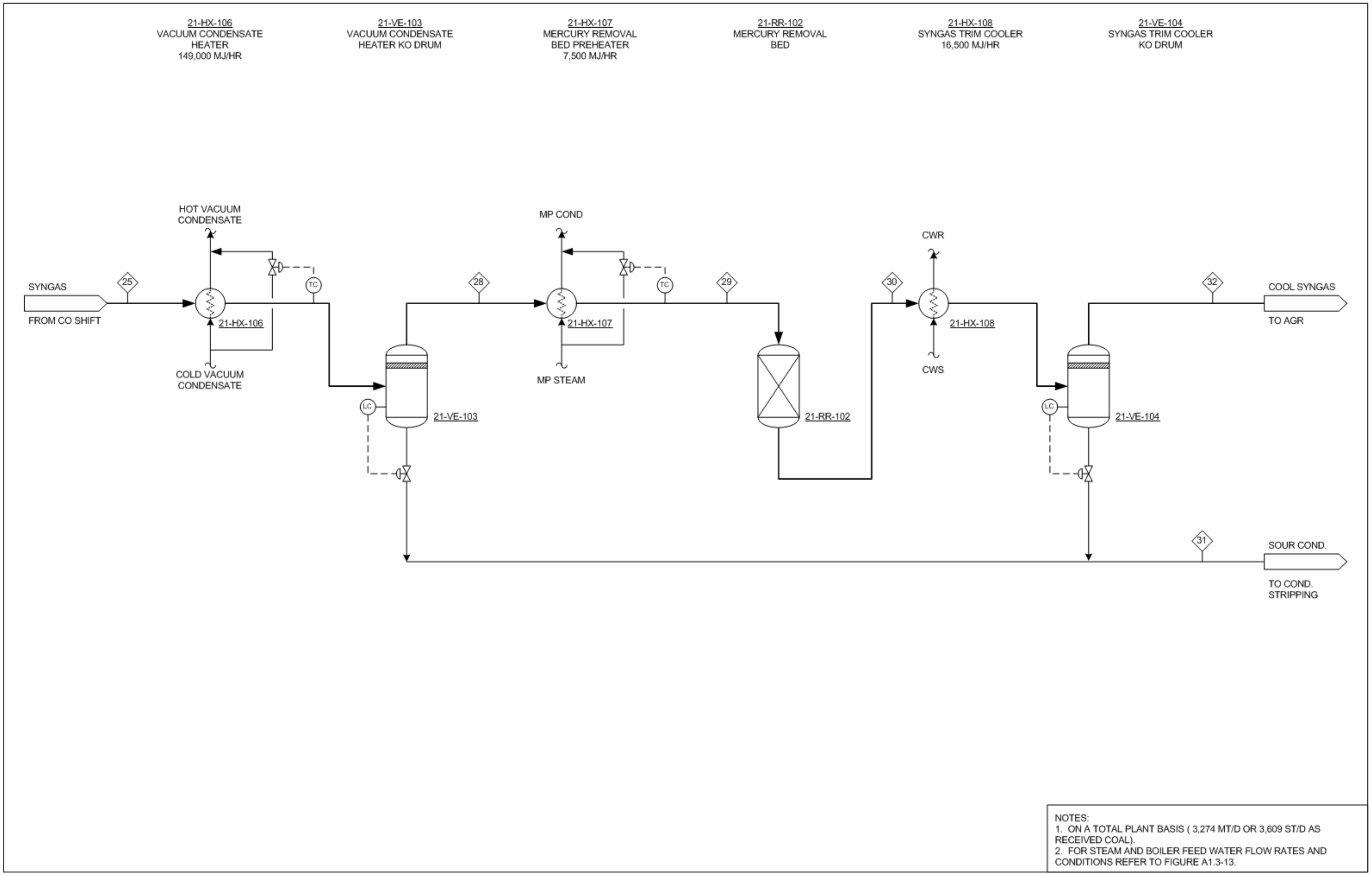

Figure A1.3 -4: Process Flow Diagram - CO Shift / Low Temperature Gas Cooling Unit (Cont'd.)

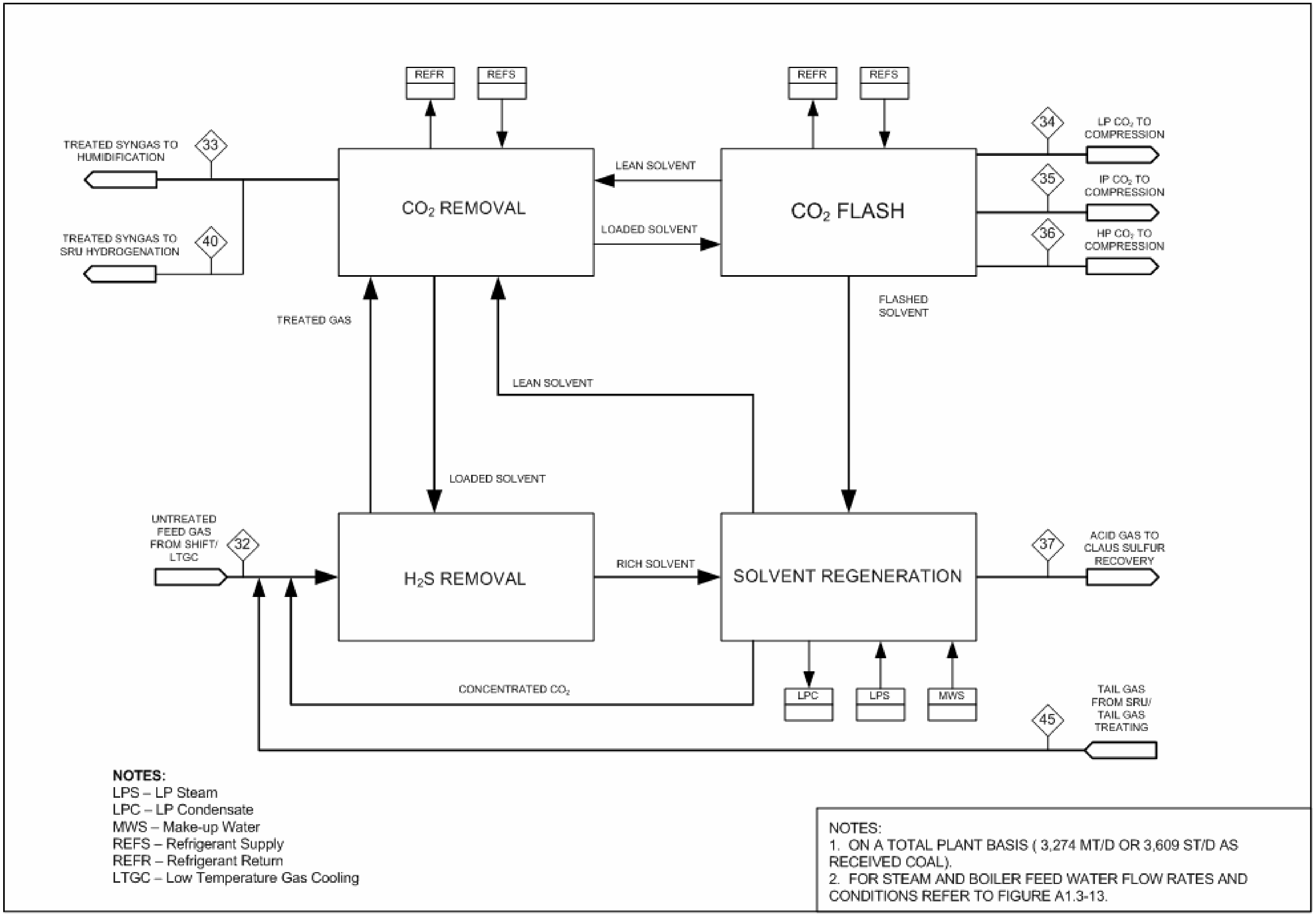

Figure A1.3 - 5: Block Flow Diagram - Acid Gas Removal Unit (Selexol®)

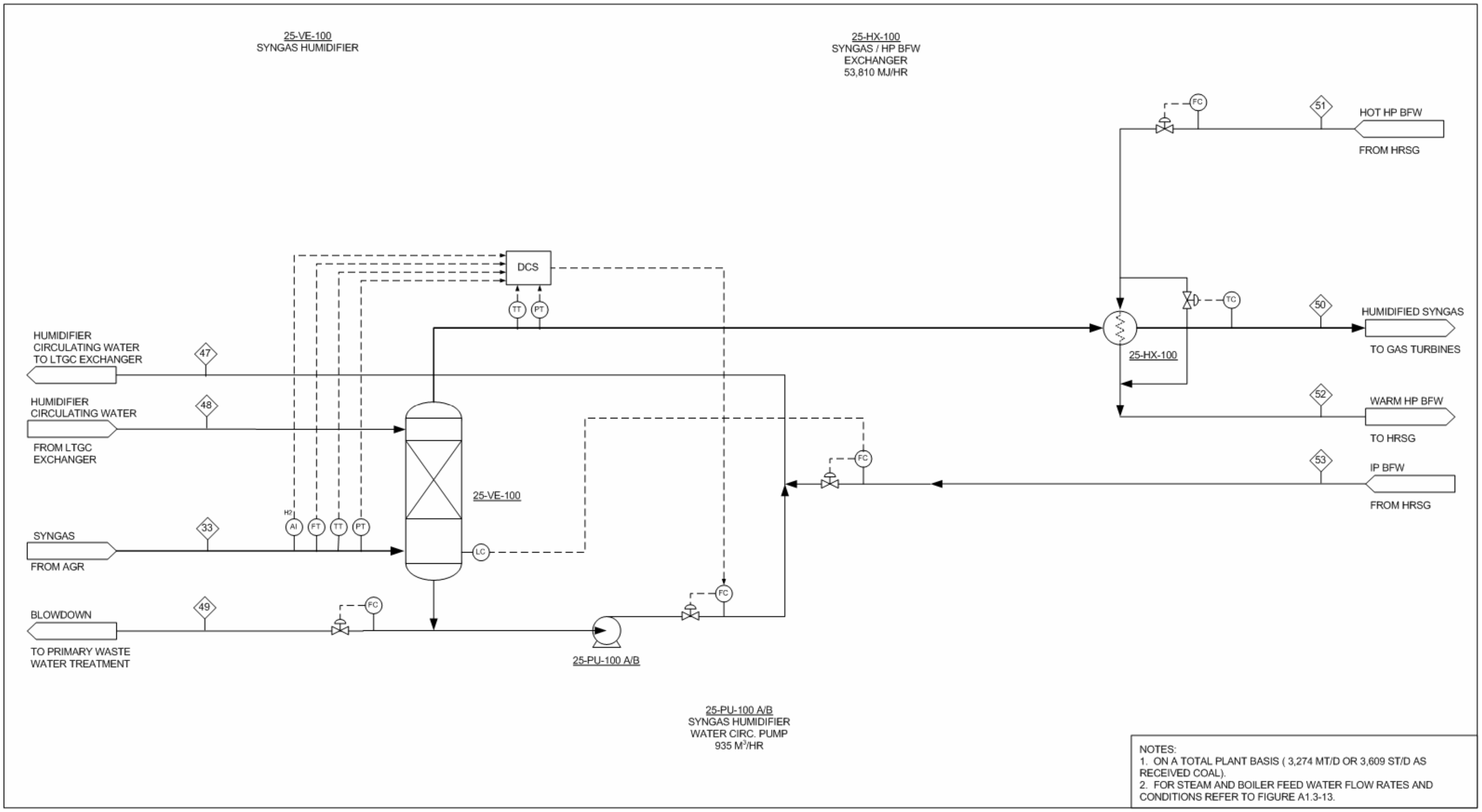

Figure A1.3 - 6: Process Flow Diagram - Syngas Humidification Unit

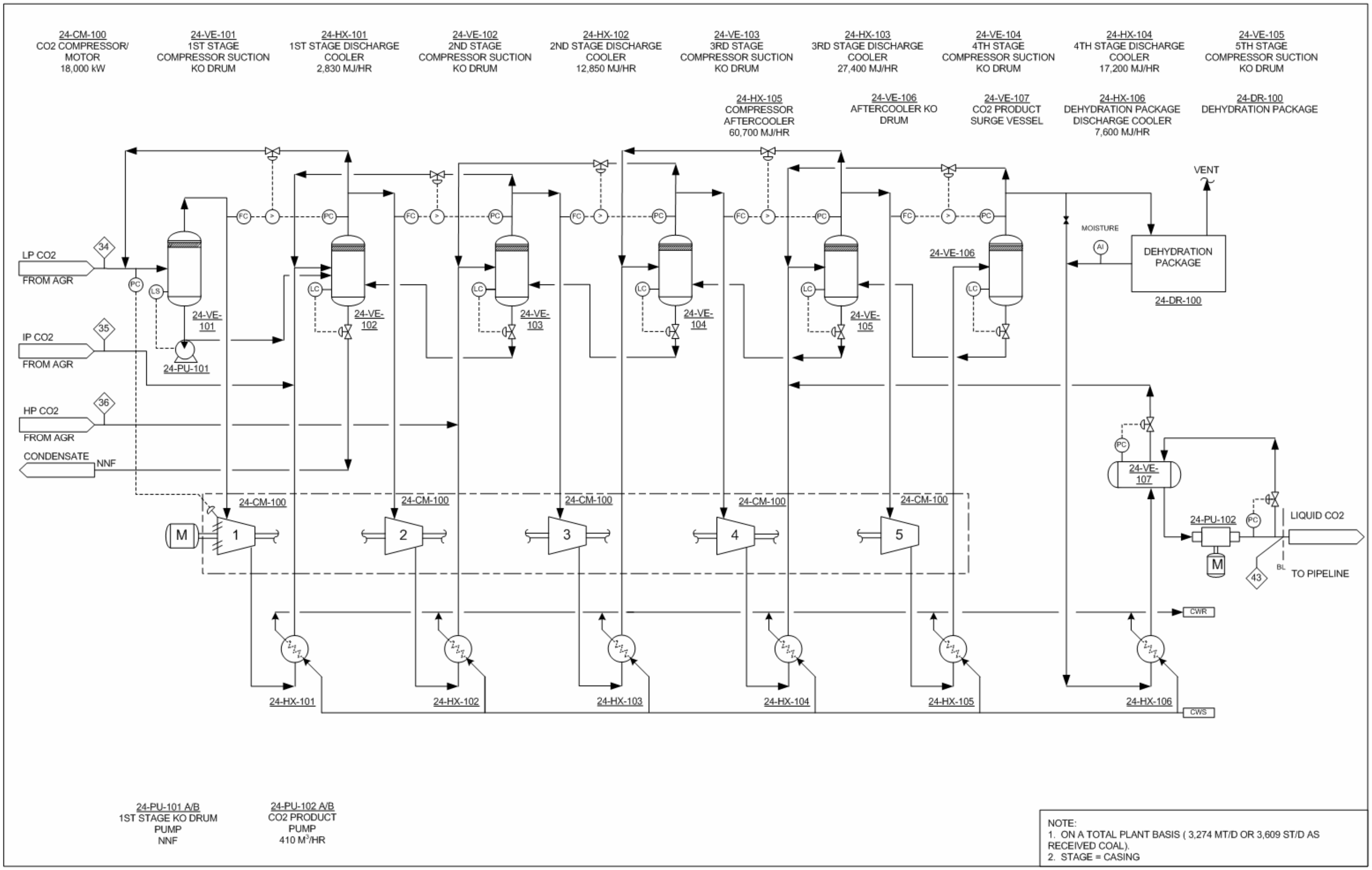

Figure A1.3 - 7: Process Flow Diagram - CO_2 Compression / Dehydration Unit

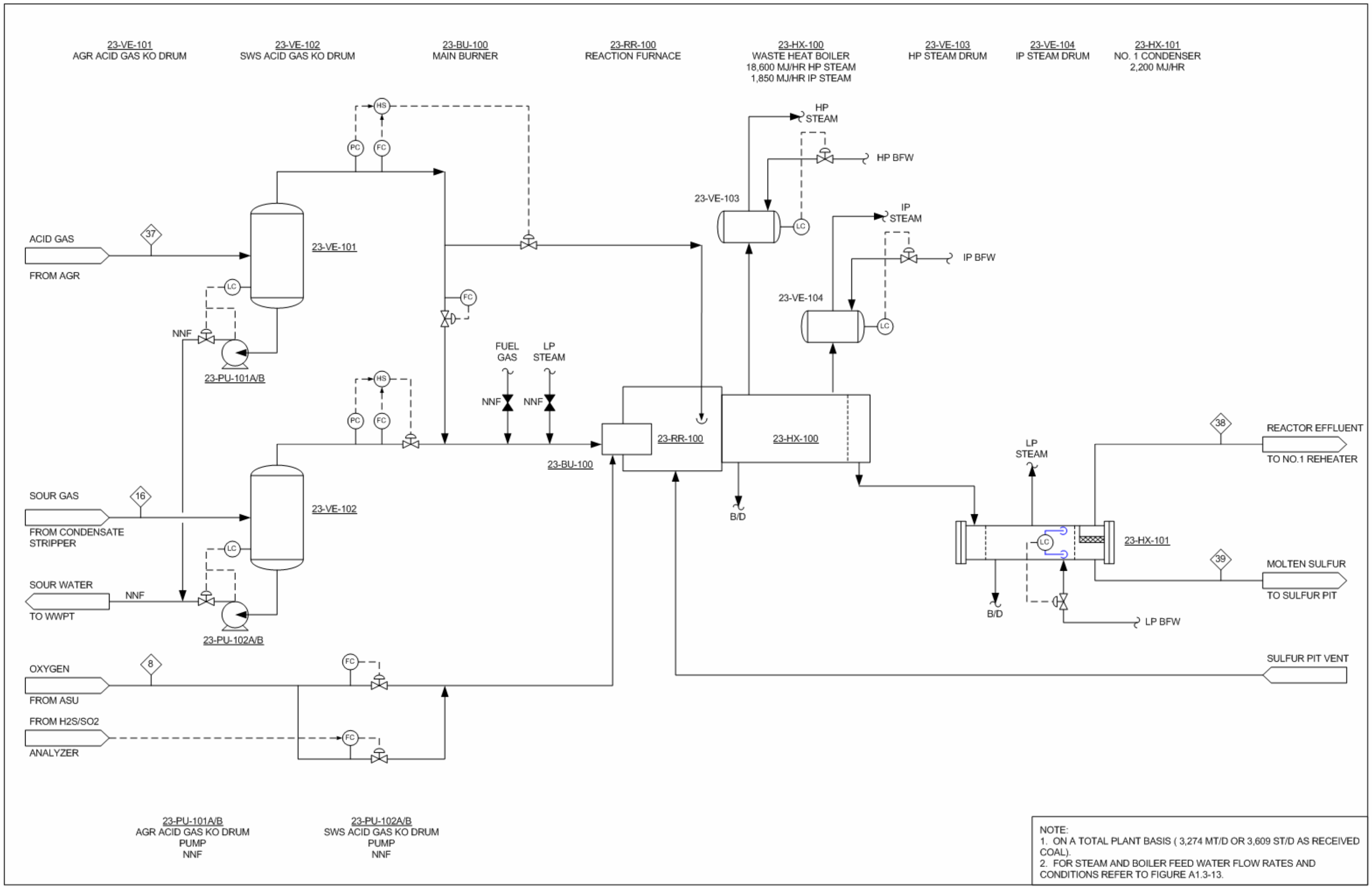

Figure A1.3 - 8: Process Flow Diagram - Sulfur Recovery / Tail Gas Treating Unit

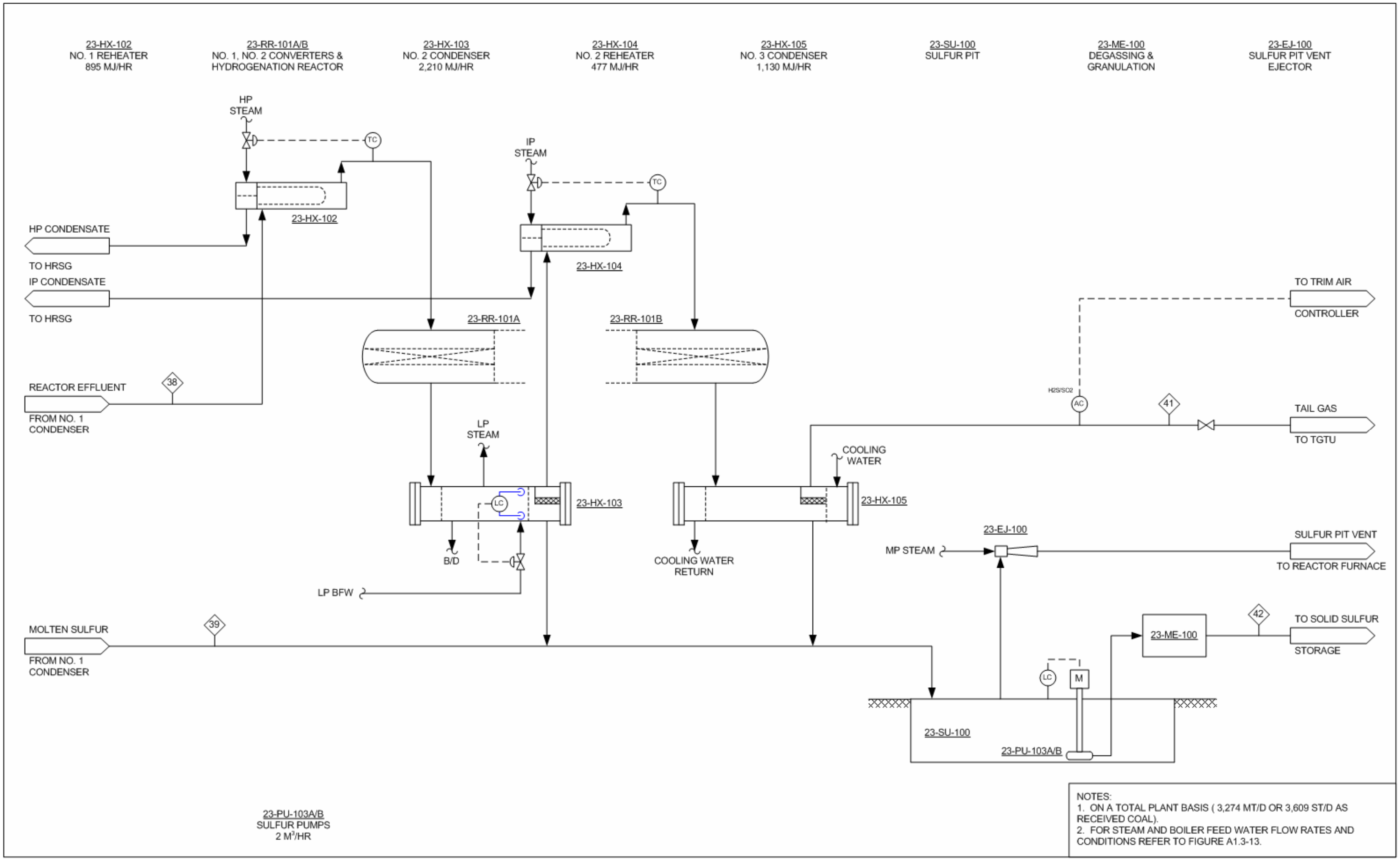

Figure A1.3 -8: Process Flow Diagram - Sulfur Recovery / Tail Gas Treating Unit (Cont'd.)

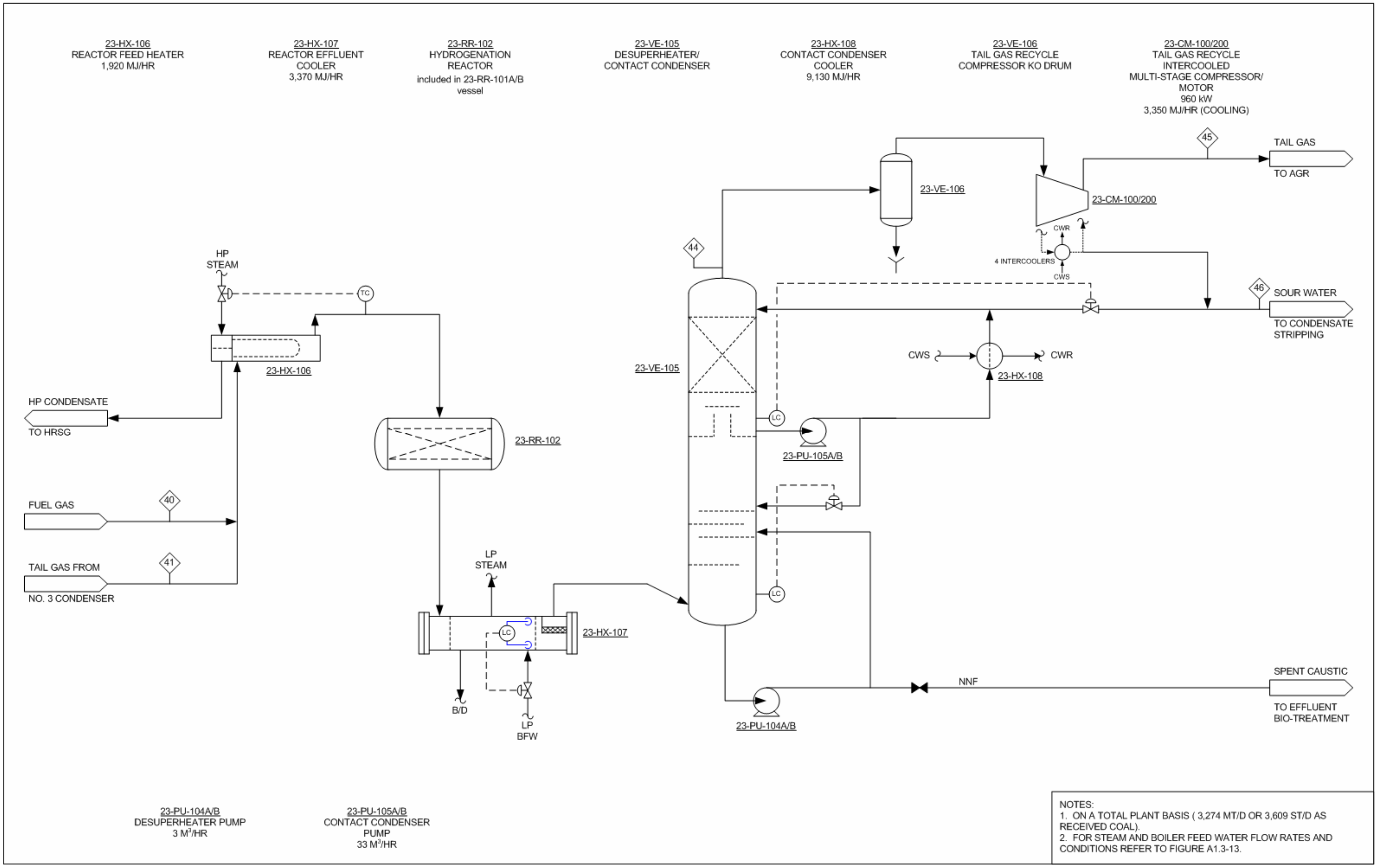

Figure A1.3 -8: Process Flow Diagram - Sulfur Recovery / Tail Gas Treating Unit (Cont'd.)

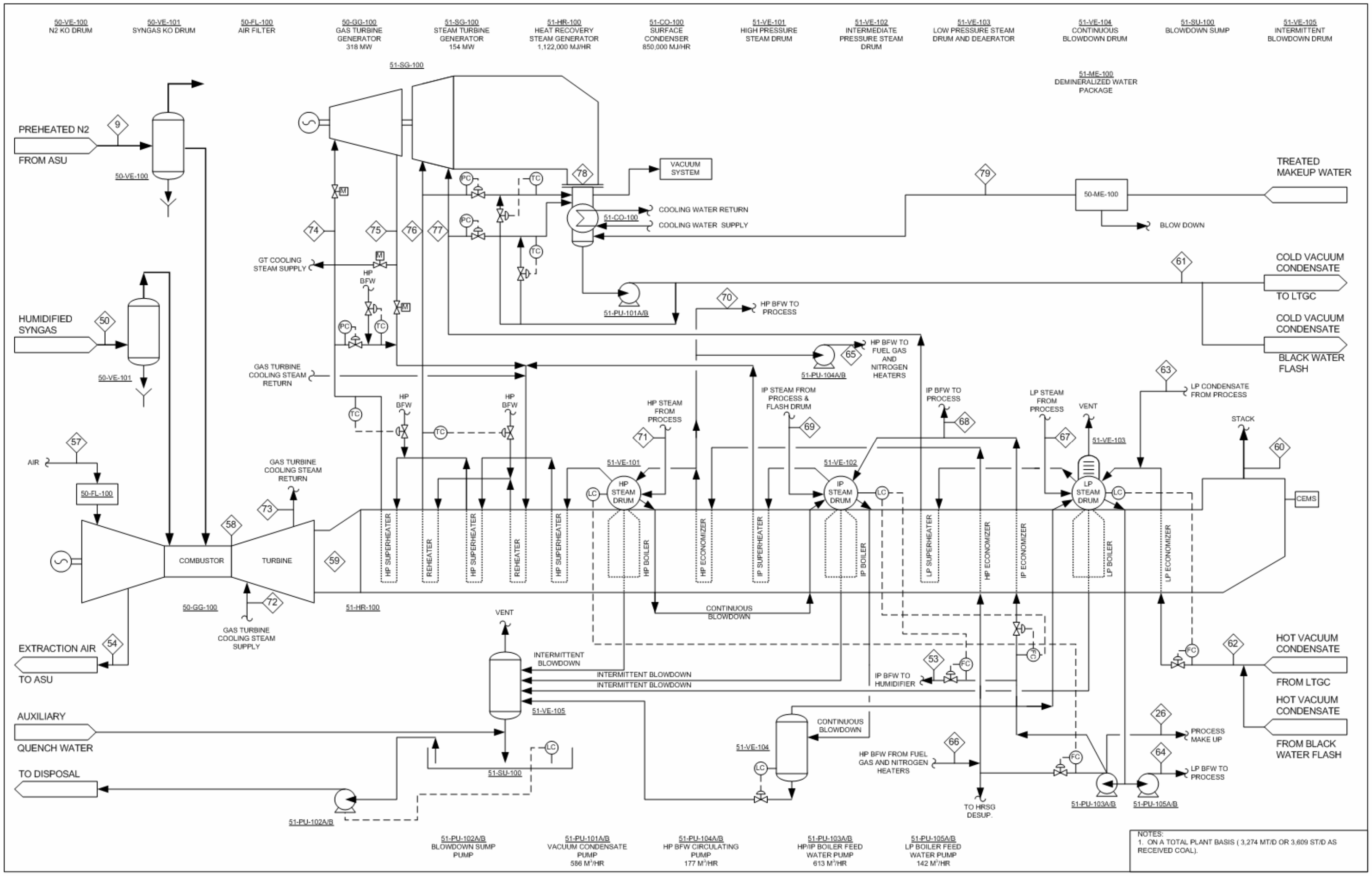

Figure A1.3 - 9: Process Flow Diagram – Power Block

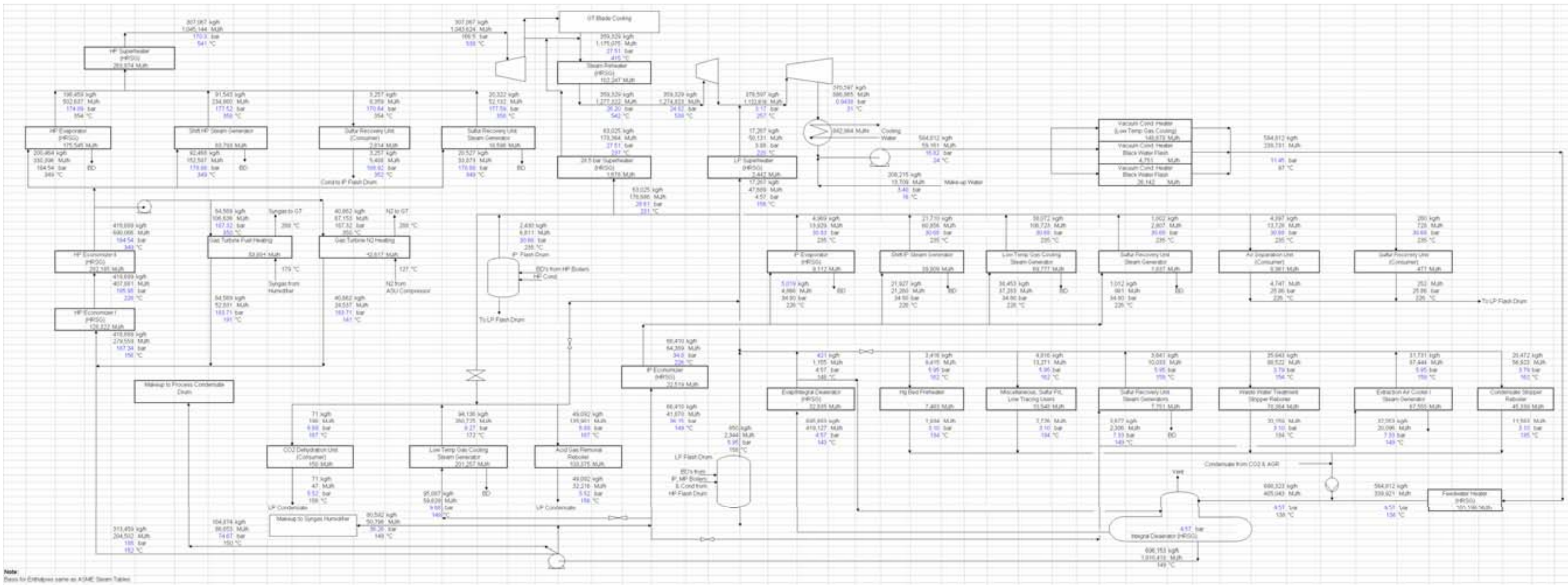

Figure A1.3 - 10: Steam Balance Diagram

Baseline Case: The Natural Gas GE Frame 7H is operated in off-design mode for syngas in IGCC. The first stator surface temperature is held constant at 1650 F (same as Natural Gas operation) by lowering the firing temperature. The engine output is limited to 1.158 times the Natural Gas case by extracting air for the The 1.158 ratio is derived from the GE 7FA+e GT.

Steam integration with other units is based oh Pittsburgh No. 8 Coal Steam Balance Received on 11/08/06.

Gross power	477305	kW
Gross electric efficiency(LHV)	66.4	%
Net power	465631	kW
Net electric efficiency(LHV)	64.78	%

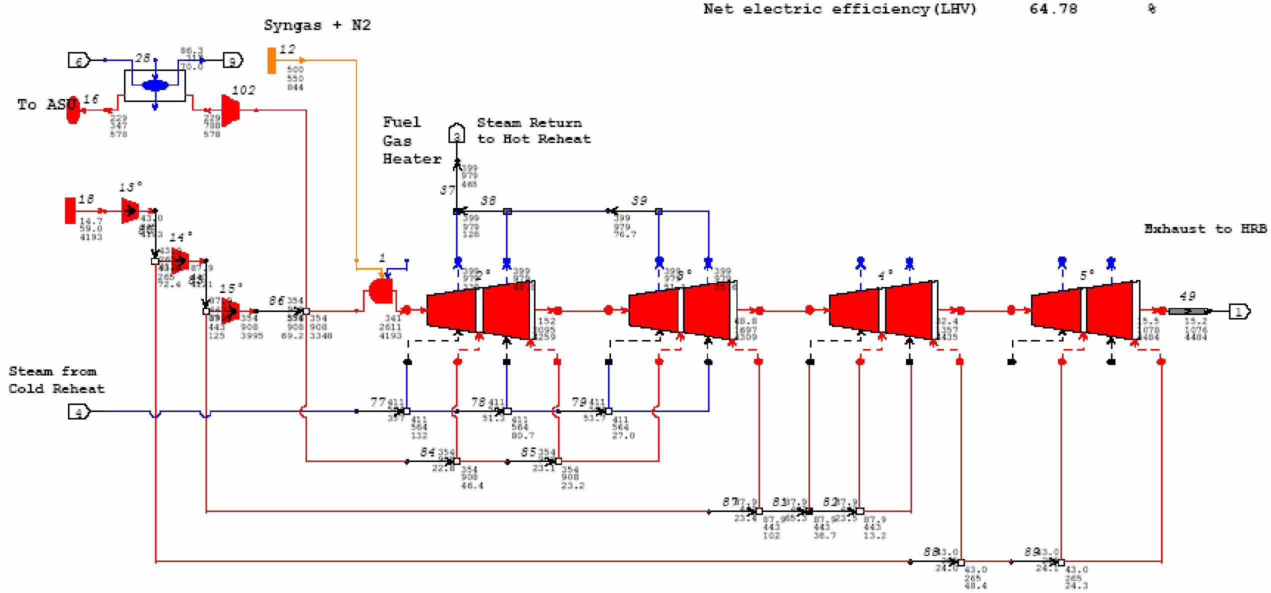

Figure A1.3 - 11: Gas Turbine Cycle Diagram - Syngas Case

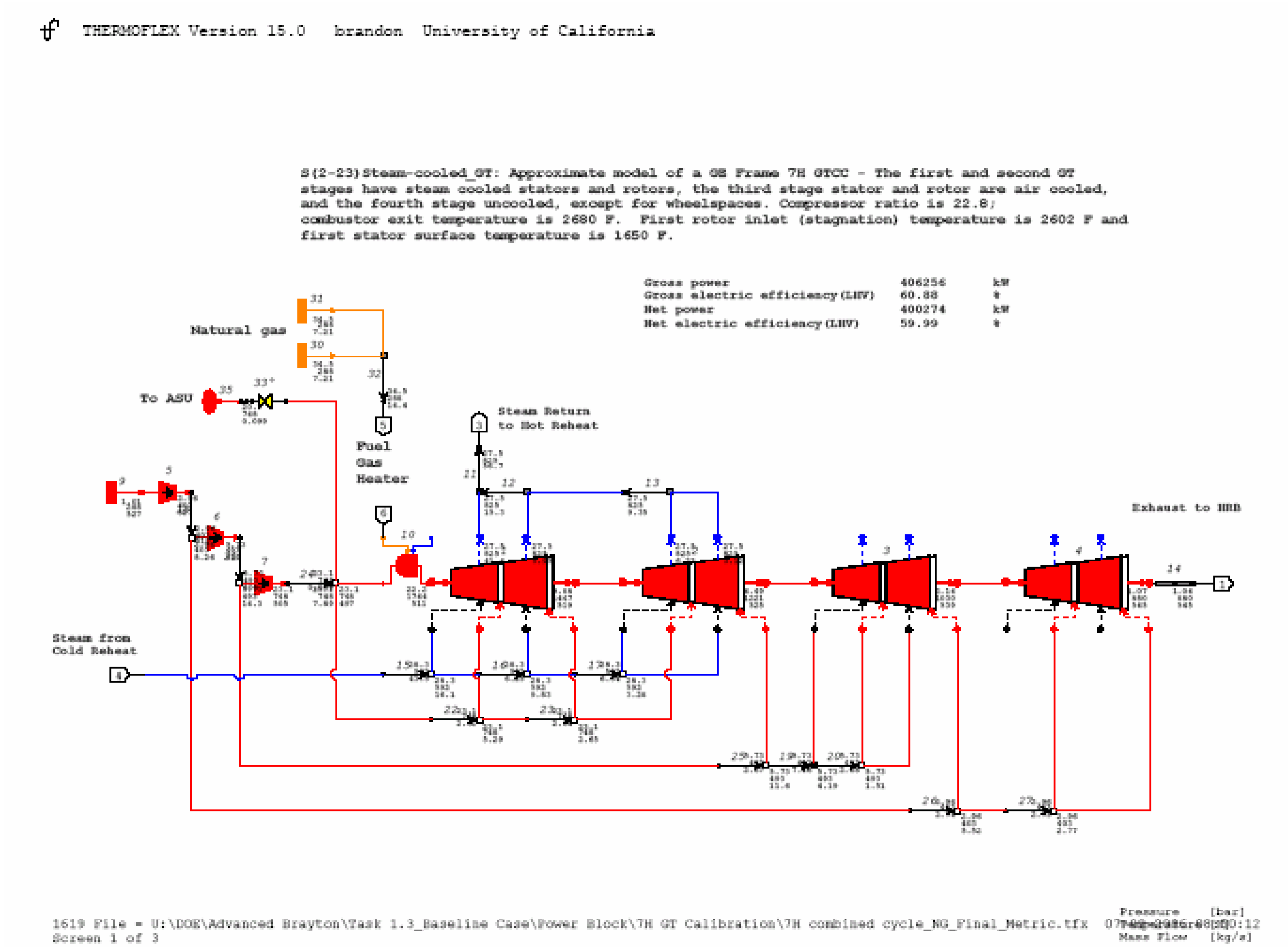

Figure A1.3 - 12: Gas Turbine Cycle Diagram - Natural Gas Case

Flows are in kg/hr.

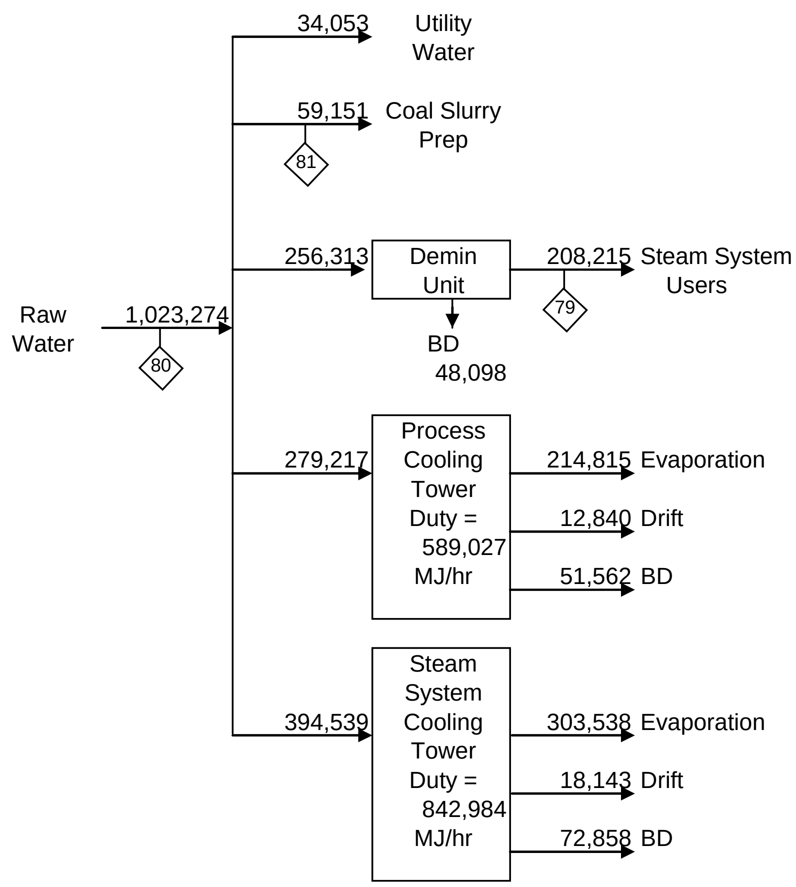

Figure A1.3 - 13: Overall IGCC Plant Water Balance

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Mol Fraction	1	2	3	4	5	6	7	8	9	10	11	12
O2		0.2077	0.2077	0.2077	0.9504	0.9500	0.9502	0.9500	0.0062	0.2090		
N2		0.7722	0.7722	0.7722	0.0230	0.0176	0.0212	0.0176	0.9891	0.7788		
Ar		0.0094	0.0094	0.0094	0.0266	0.0324	0.0286	0.0324	0.0047	0.0093		
H2												
CO												
CO2		0.0003	0.0003	0.0003						0.0003		
H2O		0.0104	0.0104	0.0104						0.0026	1.0000	1.0000
CH4												
H2S												
SO2												
Cl2												
HCl												
NH3												
COS												
Total		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Coal (As Received), kg/hr	136,416											
kgmol/hr (w/o Solids)	-	8,732	2,304	6,428	2,425	1,294	3,719	80	8,777	9,009	2,257	2,257
kg/hr (w/o Solids)	-	251,944	66,481	185,463	77,871	41,648	119,520	2,582	246,590	260,681	40,662	40,662
Temp., C	15.0	15.0	15.0	15.0	91.5	80.6	87.7	19.4	287.8	26.7	349.7	140.6
Press., bar	1.01	1.01	1.01	1.01	82.94	82.94	82.94	3.04	35.09	15.34	187.32	183.71
Enthalpy, MJ/hr	-120,462	-25,609	-6,757	-18,851	3,566	1,438	5,004	-15	67,718	-7,311	67,153	24,537
See Note	1, 2	2	2	2	2	2	2	2	2	2	3	3

Note:
1. Enthalpy expressed as HHV = 3,949,275 MJ/hr.
2. The reference state for thermodynamic properties is the standard enthalpy of formation of ideal gas at 25°C and 1 atm.
3. Enthalpy corresponds to ASME Steam Tables Basis.

Table A1.3 - 1: Stream Data

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Mol Fraction	13	14	15	16	17	18	19	20	21	22	23	24
O2			0.0000				0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
N2	0.0000		0.0042	0.0016	0.0000		0.0042	0.0042	0.0042	0.0042	0.0042	0.0049
Ar	0.0000		0.0036	0.0031	0.0000		0.0036	0.0036	0.0036	0.0036	0.0036	0.0043
H2	0.0003		0.1663	0.1493	0.0000		0.1663	0.3284	0.3284	0.3497	0.3497	0.4085
CO	0.0003		0.1936	0.0418	0.0000		0.1936	0.0315	0.0315	0.0102	0.0102	0.0120
CO2	0.0007		0.0688	0.1499	0.0000		0.0688	0.2311	0.2311	0.2524	0.2524	0.2946
H2O	0.9854	1.0000	0.5558	0.0198	0.9999	1.0000	0.5558	0.3935	0.3935	0.3722	0.3722	0.2670
CH4	0.0000		0.0020	0.0015	0.0000		0.0020	0.0020	0.0020	0.0020	0.0020	0.0023
H2S	0.0002		0.0040	0.0356	0.0000		0.0040	0.0042	0.0042	0.0042	0.0042	0.0049
SO2				0.0000	0.0000							
Cl2	0.0000											
HCl	0.0124			0.0000	0.0000							
NH3	0.0006		0.0015	0.5966	0.0001		0.0015	0.0015	0.0015	0.0015	0.0015	0.0016
COS	0.0000		0.0002	0.0009	0.0000		0.0002	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
kgmol/hr (w/o Solids)	291	447	29,163	34	2,335	1,136	29,163	29,163	29,163	29,163	29,163	24,960
kg/hr (w/o Solids)	5,322	8,062	561,919	683	42,071	20,472	561,919	561,917	561,917	561,916	561,916	486,057
kg/hr Solids	12,141	3,455										
kg/hr Total	17,463	11,516	561,919	683	42,071	20,472	561,919	561,917	561,917	561,916	561,916	486,057
Temp., C	93.3	60.3	240.1	44.9	123.4	161.8	287.8	443.5	287.5	307.9	246.1	196.2
Press., bar	1.01	3.79	67.22	2.07	2.21	3.79	66.88	65.90	64.87	63.89	63.54	63.20
Enthalpy, MJ/hr	-124,806	-140,029	-5,171,608	-3,273	-649,929	56,923	-5,119,080	-5,119,000	-5,295,102	-5,295,102	-5,364,862	-4,419,806
See Note	1	1	1	1	1	2	1	1	1	1	1	1

Note:
1. The reference state for thermodynamic properties is the standard enthalpy of formation of ideal gas at 25°C and 1 atm.
2. Enthalpy corresponds to ASME Steam Tables Basis.

Table A1.3 - 1: Stream Data – continued

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Mol Fraction	25	26	27	28	29	30	31	32	33	34	35	36
O2	0.0000			0.0000	0.0000	0.0000		0.0000	0.0000			
N2	0.0061		0.0000	0.0067	0.0067	0.0067	0.0000	0.0067	0.0124	0.0000	0.0000	0.0002
Ar	0.0053		0.0000	0.0058	0.0058	0.0058	0.0000	0.0058	0.0096	0.0000	0.0000	0.0005
H2	0.5103		0.0000	0.5575	0.5575	0.5575	0.0000	0.5575	0.9091	0.0000	0.0006	0.0200
CO	0.0149		0.0000	0.0163	0.0163	0.0163	0.0000	0.0163	0.0264	0.0000	0.0001	0.0016
CO2	0.3678		0.0007	0.4018	0.4018	0.4018	0.0003	0.4018	0.0375	0.9973	0.9980	0.9763
H2O	0.0851	1.0000	0.9983	0.0017	0.0017	0.0017	0.9880	0.0017	0.0001	0.0027	0.0012	0.0008
CH4	0.0029		0.0000	0.0031	0.0031	0.0031	0.0000	0.0031	0.0049	0.0000	0.0000	0.0006
H2S	0.0061		0.0001	0.0066	0.0066	0.0066	0.0001	0.0066	0.0000	0.0000	0.0000	0.0000
SO2									0.0000			
Cl2												
HCl												
NH3	0.0015		0.0009	0.0005	0.0005	0.0005	0.0115	0.0005				
COS	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
kgmol/hr	19,976	5,821	17,340	18,286	18,286	18,286	1,690	18,286	11,166	1,097	2,798	3,119
kg/hr	396,118	104,874	312,730	365,678	365,678	365,678	30,440	365,678	56,223	48,192	122,976	134,430
Temp., C	147.0	150.0	151.7	40.6	51.7	51.7	40.6	26.7	16.7	0.1	3.6	11.7
Press., bar	62.85	74.67	75.84	62.51	61.68	61.68	62.51	61.34	36.61	1.08	3.24	10.00
Enthalpy, MJ/hr	-3,271,122	-1,613,839	-4,799,605	-2,940,351	-2,932,870	-2,932,870	-479,413	-2,949,342	-204,974	-432,070	-1,102,083	-1,202,147
See Note	1	1	1	1	1	1	1	1	1	1	1	1

Note: 1. The reference state for thermodynamic properties is the standard enthalpy of formation of ideal gas at 25°C and 1 atm.

Table A1.3 - 1: Stream Data – continued

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Mol Fraction	37	38	39	40	41	42	43	44	45	46	47	48
O2		0.0000		0.0000	0.0000						0.0000	0.0000
N2	0.0013	0.0445		0.0124	0.0461		0.0001	0.0822	0.0845	0.0001	0.0000	0.0000
Ar	0.0025	0.0090		0.0096	0.0093		0.0003	0.0169	0.0174	0.0000	0.0000	0.0000
H2	0.1614	0.0996		0.9091	0.1032		0.0091	0.3690	0.3793	0.0000	0.0001	0.0001
CO	0.0071	0.1115		0.0264	0.1155		0.0008	0.0220	0.0226	0.0000	0.0000	0.0000
CO2	0.3126	0.1554		0.0375	0.1610		0.9895	0.4659	0.4788	0.0083	0.0000	0.0000
H2O	0.0565	0.4666		0.0001	0.5557			0.0281	0.0010	0.9905	0.9999	0.9999
CH4	0.0017	0.0000		0.0049	0.0000		0.0003	0.0002	0.0002	0.0000	0.0000	0.0000
H2S	0.4235	0.0721		0.0000	0.0024		0.0000	0.0153	0.0158	0.0009	0.0000	0.0000
SO2		0.0408		0.0000	0.0061			0.0000	0.0000	0.0000	0.0000	0.0000
Cl2												
HCl	0.0000	0.0000			0.0000			0.0000	0.0000	0.0000		
NH3	0.0329	0.0000			0.0000			0.0004	0.0004	0.0000		
COS	0.0006	0.0005		0.0000	0.0005		0.0000	0.0001	0.0001	0.0000	0.0000	0.0000
Total	1.0000	1.0000		1.0000	1.0000		1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Sulfur, kg/hr			2,658			3,927						
kgmol/hr	294	378	41	8	365	81	7,005	205	200	171	45,707	45,707
kg/hr	8,950	9,558	2,658	39	8,290	3,927	305,434	5,315	5,215	3,115	823,448	823,448
Temp., C	48.9	176.7	250.0	15.3	287.8	25.0	31.8	26.6	26.7	28.2	126.4	185.0
Press., bar	2.07	1.87	1.89	1.30	1.30	1.01	138.93	1.24	64.78	3.45	40.96	40.27
Enthalpy, MJ/hr	-43,284	-73,650	4,460	-143	-74,228	0	-2,798,852	-39,592	-38,421	-48,844	-12,763,617	-12,532,081
See Note	1	1	1	1	1	1	1	1	1	1	1	1

Note: 1. The reference state for thermodynamic properties is the standard enthalpy of formation of ideal gas at 25°C and 1 atm.

Table A1.3 - 1: Stream Data – continued

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Mol Fraction	49	50	51	52	53	54	55	56	57	58	59	60
O2	0.0000	0.0000				0.2074	0.2074	0.2074	0.2074	0.0784	0.0848	0.0848
N2	0.0000	0.0088				0.7728	0.7728	0.7728	0.7729	0.6899	0.6890	0.6890
Ar	0.0000	0.0069				0.0092	0.0092	0.0092	0.0093	0.0083	0.0083	0.0083
H2	0.0001	0.6500										
CO	0.0000	0.0189										
CO2	0.0001	0.0268				0.0003	0.0003	0.0003	0.0003	0.0109	0.0102	0.0102
H2O	0.9999	0.2851	1.0000	1.0000	1.0000	0.0103	0.0103	0.0103	0.0101	0.2125	0.2076	0.2076
CH4	0.0000	0.0035										
H2S	0.0000	0.0000										
SO2	0.0000	0.0000										
Cl2												
HCl												
NH3												
COS	0.0000	0.0000										
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
kgmol/hr	22	15,618	3,584	3,584	4,474	9,079	9,079	9,079	65,913	71,834	76,632	76,632
kg/hr	401	136,415	64,569	64,569	80,592	261,950	261,950	261,950	1,901,912	1,901,772	2,033,714	2,033,714
Temp., C	123.7	287.8	349.7	190.6	149.0	483.9	421.3	177.8	15.0	1,432.8	581.5	117.3
Press., bar	35.92	35.58	187.32	183.71	36.26	24.13	15.75	15.55	1.01	23.50	1.07	1.01
Enthalpy, MJ/hr	-6,220	-1,153,079	106,636	52,831	50,796	102,173	84,198	16,659	-188,413	-502,253	-2,807,870	-3,943,507
See Note	1	1	2	2	2	1	1	1	1	1,3	1,3	1,3

Note:
1. The reference state for thermodynamic properties is the standard enthalpy of formation of ideal gas at 25°C and 1 atm.
2. Enthalpy corresponds to ASME Steam Tables Basis.

Table A1.3 - 1: Stream Data – continued

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Mol Fraction	61	62	63	64	65	66	67	68	69	70	71	72
H2O	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
kgmol/hr	32,462	32,462	6,301	7,248	5,841	5,841	956	3,408	3,223	6,272	6,029	12,303
kg/hr	584,812	584,812	113,511	130,579	105,231	105,231	17,215	61,391	58,056	112,995	108,608	221,645
Temp., C	23.7	97.4	134.7	148.6	349.7	171.3	156.8	225.5	235.1	348.9	356.0	295.3
Press., bar	16.82	11.45	4.57	11.75	187.32	183.71	4.57	34.80	30.68	178.88	174.09	28.31
Enthalpy, MJ/hr	59,161	238,731	85,566	81,866	173,789	77,368	47,576	59,523	162,756	186,460	278,633	662,264
See Note	1	1	1	1	1	1	1	1	1	1	1	1

Note: 1. Enthalpy corresponds to ASME Steam Tables Basis.

Table A1.3 - 1: Stream Data – continued

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Mol Fraction	73	74	75	76	77	78	79
H2O	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Total	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
kgmol/hr	11,703	17,045	17,045	19,946	20,904	20,904	11,558
kg/hr	210,833	307,067	307,122	359,329	376,597	376,597	208,215
Temp., C	526.1	537.8	295.7	538.0	257.1	30.5	15.6
Press., bar	27.51	166.51	28.58	3.17	3.17	0.04	3.40
Enthalpy, MJ/hr	741,822	1,043,624	917,668	1,274,823	1,122,918	886,865	13,709
See Note	1	1	1	1	1	1	1

Note: 1. Enthalpy corresponds to ASME Steam Tables Basis.

Table A1.3 - 1: Stream Data - continued

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Mol Fraction	80	81	82
O2			
N2			0.0000
Ar			0.0000
H2			0.0000
CO			0.0000
CO2			0.0000
H2O	1.0000	1.0000	0.9995
CH4			0.0000
H2S			0.0000
SO2			
Cl2			
HCl			
NH3			0.0005
COS			0.0000
Total	1.0000	1.0000	1.0000
kgmol/hr	56,800	3,283	1,539
kg/hr	1,023,274	59,151	27,721
Temp., C	15.6	15.6	26.7
Press., bar	1.014	1.014	1.4
Enthalpy, MJ/hr	67,139	3,881	-441,987
See Note	1	1	0.0

Note: 1. The reference state for thermodynamic properties is the standard enthalpy of formation of ideal gas at 25°C and 1 atm.

Table A1.3 - 2: ASU Functional Specifications - General

	Units	Quantity	Requirements (See Notes Below)
GT Air Extraction			Temperature and pressure correspond to conditions at GT extraction point. Air may be either (1) cooled and utilized in the ASU or (2) expanded hot through a turboexpander and then cooled and utilized in the ASU.
Flow Rate	kg/hr	261,950	
Temperature		484	
Pressure	Bar	24.13	
HP O_2			95 mol% O_2 purity
Flow Rate (based on contained O_2)	kg/hr	113,081	
Pressure	Bar	82.94	
LP O_2			95 mol% O_2 purity
Flow Rate (based on contained O_2)	kg/hr	2,432	
Pressure	Bar	3.04	
IP N_2 (GT Injection)			O_2 Content < 1.0 mol%
Flow Rate	kg/hr	246,507	
Pressure	Bar	35.09	

Notes:
1. All compressors to be motor driven
2. Supply of utilities outside ASU scope
3. Cooling water available at 15.6°C or 60°F
4. Flow rates shown below are on total plant basis.

Table A1.3 - 3: ASU Functional Specifications - Storage Requirements

	Capacity	
Liquid O2 (based on Contained O2)	Hr	8
Gaseous O2 (please recommend)	Min	Approx. 3.5

Table A1.3 - 4: ASU Functional Specifications - Ambient Air Composition

Component	Mole %
O_2	20.77
N_2	77.22
CO_2	0.03
H_2O	1.04

Table A1.3 - 5: Coal Receiving And Handling Unit Functional Specifications

General

1. Coal handling sections include coal receiving, storage, stacking and reclaiming.
2. 3273 MT/D of "as received' Pittsburgh No.8 coal
3. Hardgrove grinding index = 50, size > 50.0 mm = 3%
4. Wed-western location.

Facilities Description

Facilities for transportation, storage and reclaiming of coal shall include the following:

- Truck unloading facilities
- Transfer of coal from the trucks to the coal storage area
- 14 days covered live coal storage
- Coal stacking
- Coal reclaiming (multiple units for increased availability)
- Coal transport from storage to the gasification battery limits
- Dust collection system in the storage as well as well transfer points in the conveying system
- Conveyers for transfer of coal
- Dust control and suppression via water / chemicals spraying
- Collection of run-off water and slag fines
- Transfer of the run-off water to water treatment section
- Fire protection
- Safety equipment
- Magnetic separators to remove tramp iron
- 20 day back-up dead coal storage with vegetation for dust control
- Noise control
- Covered conveyers
- Bin vibrators
- Weigh scales
- Conveying of coal from dead storage to covered storage
- Metal detectors
- Sampling systems
- Electrical systems
- Control and supervision system including programmable logic controller for maximizing automatic operations
- Control room
- Distribution of utilities (fire water, potable water, compressed air and electricity) within the battery limits

Interface Definition

The coal leaving the "Feed Receiving and Handling System" is fed to feed bins in gasification unit which provide the feed to wet rod mills. The scope of the "Feed Receiving and Handling System" should consist of providing the coal to these feed bins.

Emissions and Effluents

All the coal handling systems (unloading, storage, conveying, reclaiming) except the dead coal storage are covered to minimize particulate emissions. The transfer bins and hoppers shall include bin vent filters to capture dust from displaced air. Induced air dust collectors shall be installed at all transfer points. The dumping of coal from incoming trippers associated with high impact velocity from free fall of over 60 feet shall be avoided to minimize coal degradation and segregation as well as dust emissions. The target design level of particulate (PM10 and PM25) is 5.9 mg/Nm3.

The aqueous effluents from the system (contaminated rain water, water used for dust control, melting snow, water used for fire protection) shall be routed to a sump to separate the coal fines using filters for recycle to the coal storage area. The aqueous effluent shall be routed to the waste water treatment section. The below ground system shall include trenches covered with grating to collect all coal contaminated wash water for recycle.

Fire Protection

All the coal handling equipment shall include fire protection systems. Safety systems including temperature measurement, combustion gas analysis, alarms, safety showers and eye wash stations and others as needed shall be provided. Mobile fire equipment shall be provided as well.

Noise

The noise limits shall be in compliance with EPA and OSHA regulations. Typically, the noise shall not exceed 85 dba at 3 feet from the source and 60 dba in the nighttime and 70 dba in the daytime at the plant fence line. The coal unloading operations shall be limited to 5 days per week and 8 hours per day. The transfer of coal to the plant shall be done 7 days per week and 16 hours per day.

Table A1.3 - 6: Gasification Unit Functional Specifications - Coal Grinding and Slurry Preparation Subsystem

Technology Type	Rod Mills -Wet Coal Grinding (See Notes)
Operating Conditions (Total Plant Basis)	
Inlet: Coal	136,416 kg/hr as received Pittsburgh #8 coal
Outlet: Coal Slurry	195,530 kg/hr with particle size consistent with GE Energy slurry feed, entrained bed oxygen blown gasifier
Slurry Strength	65.6% solids

Table A1.3 - 7: Gasification Unit Functional Specifications - Gasifier Subsystem

Technology Type	GE Energy Slurry Feed, Entrained Bed Oxygen Blown Gasifier (See Notes)
Gasifier Effluent Cooling	Total Quench (direct contact cooling with water)
Operating Conditions (Total Plant Basis)	
Inlet: Coal Slurry	195,530 kg/hr coal + water
Outlet: Raw Gas	299,440 kg/hr syngas (Prior to Quenching) at 72.6 bar and 1,371ºC with H_2 + CO = 10,497 kg moles/hr

Table A1.3 - 8: Gasification Unit Functional Specifications - Syngas Scrubber Subsystem

Technology Type	Direct Contact Water Scrubber (See Notes)
Operating Conditions (Total Plant Basis)	
Inlet-Gas	579,742 kg/hr raw syngas at 69.6 bar, 243°C
Inlet Water	66,848 kg/hr at 76 bar and 151°C
Outlet-Gas	563,714 kg/hr scrubbed syngas at 67.2 bar, 240°C
Contaminant Removal, %	Particulate, 99.9%
Particulate Slurry Strength	4% solids

Table A1.3 - 9: Gasification Unit Functional Specifications - Slag Recovery and Handling Subsystem

Technology Type	Wet Lock Hopper System (See Notes)
Operating Conditions (Total Plant Basis)	
Inlet	Solids (coarse and fines) containing water
Outlet	12,141 kg/hr solids + 5,353 kg/hr water, near ambient conditions (1.01 bar, 15°C)
Dewatered Slag Moisture Content	$\leq$ 30%

Table A1.3 - 10: Gasification Unit Functional Specifications - Black Water, Grey Water and Waste Water Handling Subsystem

Technology Type	Settling Tanks and Filtration (See Notes)
Operating Conditions (Total Plant Basis)	
Inlet	Solids (fines) containing water
Outlet-Treated Waste Water	27,721 kg/hr (quality compatible for bio-treatment unit)
Outlet-Filter Cake (Fine Slag)	3,455 kg/hr solids + 8,062 kg/hr water, near ambient conditions (1.01 bar, 15°C)
Filter Cake Moisture Content	≤ 70%

Notes:

1. All rotating equipment to be motor driven
2. Supply of utilities outside supplier scope
3. Cooling water available at 15.6°C or 60°F .

Table A1.3 - 11: Selexol AGR Functional Specification – Feed Gas Definition

Mol Fraction	
N_2	0.006684
Ar	0.005811
H_2	0.557469
CO	0.016197
CO_2	0.401829
H_2O	0.001649
CH_4	0.003122
H_2S	0.006637
NH_3	0.00059
COS	1.17E-05
Total	1.000000
kgmol/hr	18289.02
kg/hr	365741.8
Temperature, °C	27.6
Pressure, bar	61.3

Table A1.3 - 12: Selexol AGR Functional Specification – Product Specifications

Treated Syngas Stream	
Total H_2S + COS	≤ 10 ppmv
Pressure	36.61 bar (utilize a cold gas expander to recover power and generate refrigeration for solvent chilling)
CO_2 Stream	
Overall CO_2 Capture	90% total carbon removal (CO_2 + CO + CH_4)
CO_2 Purity	Limit H_2S to < 22 ppmV
Pressure of CO_2 Stream(s)	Leaving the AGR at maximum Pressure(s), the CO_2 being ultimately compressed to 138 barg or 2000 psig.
Acid Gas Stream	
Total H_2S + COS	Acceptable to an O_2 blown Claus unit (20 mol % Minimum).
Pressure	Suitable to a Claus unit (2.07 bar)

Notes:

1. All compressors to be motor driven
2. Supply of utilities outside AGR supplier scope
3. Cooling water available at 15.6°C or 60°F.

Table A1.3 - 13: Equipment List Unit 21 - Sour Shift / LT Gas Cooling

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Equipment Number	Service	Number of Operating (spare)	Equipment Description (per Operating Train Basis)		Remarks
21-HE-100	Electric Startup Heater	1 (0)	2,644	GJ/hr	
21-HX-100	Reactor Feed/Effluent Exchanger	1 (0)	52,600	GJ/hr	
21-HX-101	HP Steam Generator	1 (0)	83,800	GJ/hr	
21-HX-102	IP Steam Generator 1	1 (0)	39,800	GJ/hr	
21-HX-103	IP Steam Generator 2	1 (0)	69,800	GJ/hr	
21-HX-104	MP Steam Generator	1 (0)	202,000	GJ/hr	
21-HX-105	Syngas Humidifier Circ. Water Heater	1 (0)	232,000	GJ/hr	
21-HX-106	Vacuum Condensate Heater	1 (0)	149,000	GJ/hr	
21-HX-107	Mercury Removal Bed Preheater	1 (0)	7,500	GJ/hr	
21-HX-108	Syngas Trim Cooler	1 (0)	16,500	GJ/hr	
21-PU-100	Process Condensate Pump	1 (1)	232	m3/hr	
21-PU-101	Stripper Recycle Pump	1 (1)	42	m3/hr	
21-RR-100	Shift Reactor 1	1 (0)	4,727	kg moles/hr of CO Converted	
21-RR-101	Shift Reactor 2	1 (0)	621	kg moles/hr of CO Converted	
21-RR-102	Mercury Removal Bed	1 (0)	18,286	kg moles/hr of Syngas Treated	
21-VE-100	Hot Condensate KO Drum	1 (0)	561,916 / 75,860	kg/hr of Saturated Syngas, kg/hr Condensate	
21-VE-101	Syngas Humidifier Cric. Water KO Drum	1 (0)	486,057 / 89,939	kg/hr of Saturated Syngas, kg/hr Condensate	
21-VE-102	Process Condensate Return Drum	1 (0)	374,014	kg/hr Condensate	
21-VE-103	Vacuum Condensate Heater KO Drum	1 (0)	396,118 / 30,440	kg/hr of Saturated Syngas, kg/hr Condensate	
21-VE-104	Syngas Trim Cooler KO Drum	1 (0)	365,678 / NNF	kg/hr of Saturated Syngas, kg/hr Condensate	

Table A1.3 - 14: Equipment List Unit 23 - Claus Sulfur Recovery Unit

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Equipment Number	Service	Number of Operating (spare)	Equipment Description	Remarks
23-BU-100	Main Burner	1 (0)	108.6 kg moles/hr Acid + Sour gasses	
23-EJ-100	Sulfur Pit Vent Ejector	1 (0)		
23-HX-100	Waste Heat Boiler	1 (0)	18.64 GJ/hr, 178 bar (HP) Steam 1.79 GJ/hr, 31 bar (IP) Steam	
23-HX-101	No. 1 Condenser	1 (0)	2.20 GJ/hr	
23-HX-102	No. 1 Reheater	1 (0)	0.90 GJ/hr	
23-HX-103	No. 2 Condenser	1 (0)	2.21 GJ/hr	
23-HX-104	No. 2 Reheater	1 (0)	0.48 GJ/hr	
23-HX-105	No. 3 Condenser	1 (0)	1.13 GJ/hr	
23-HX-106	Reactor Feed Heater	1 (0)	1.92 GJ/hr	
23-HX-107	Reactor Effluent Cooler	1 (0)	3.37 GJ/hr	
23-HX-108	Contact Condenser Cooler	1 (0)	9.13 GJ/hr	
23-PU-101	AGR Acid Gas KO Drum Pump	1 (1)		Normally no flow
23-PU-102	SWS Acid Gas KO Drum Pump	1 (1)		Normally no flow

Table A1.3 - 14: Equipment List – Unit 23 Claus Sulfur Recovery Unit - continued

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Equipment Number	Service	Number of Operating (spare)	Equipment Description	Remarks
23-PU-103	Sulfur Pumps	1 (1)	2 m3/hr	
23-PU-104	Desuperheater Pump	1 (1)	3 m3/hr	
23-PU-105	Contact Condenser Pump	1 (1)	33 m3/hr	
23-RR-100	Reaction Furnace	1 (0)	392 kg moles/hr of Reaction Products	
23-RR-101A	No. 1 Converter	1 (0)	378 kg moles/hr of Feed Gas	
23-RR-101B	No. 2 Converter	1 (0)	367 kg moles/hr of Feed Gas	
23-RR-102	Hydrogenation Reactor	1 (0)	373 kg moles/hr of Feed Gas	
23-SU-100	Sulfur Pit	1 (0)	94,200 kg Molten Sulfur	24 hr Storage
23-VE-101	AGR Acid Gas KO Drum	1 (0)	294 kg moles/hr of Feed Gas	
23-VE-102	SWS Acid Gas KO Drum	1 (0)	34 kg moles/hr of Feed Gas	
23-VE-103	HP Steam Drum	1 (0)	20,322 kg/hr, 178 bar Steam	Included in 23-HX-100
23-VE-104	IP Steam Drum	1 (0)	1,002 kg/hr, 31 bar Steam	Included in 23-HX-100
23-VE-105	Desuperheater / Contact Condenser	1 (0)	370 kg moles/hr of Feed Gas	
23-VE-106	Tail Gas Recycle Compressor KO Drum	1 (0)	205 kg moles/hr of Feed Gas	
23-CM-100	Tail Gas Recycle Compressor (Intercoole	1 (1)	960 kW (3,350 MJ/hr Intercooling Duty)	Isentropic efficiency: Casing 1: 0.84, Casing 2: 0.79, Casing 3: 0.72, Casing 4: 0.62
23-ME-100	Degassing and Granulation	1 (0)	3,927 kg/h Sulfur	

Table A1.3 - 15: Equipment List Unit 24 - CO_2 Compression

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Equipment Number	Service	Number of Operating (spare)	Equipment Description (per Operating Train Basis)		Remarks
24-CM-100 (24-VE-102, 103, 104, 105 and 24-HX-101, 102, 103, 104)	CO2 Compressor (with Intercoolers and Suction KO Drums)	1 (0)	18,000 122,976 134,430 305,586	kW w/ 48,192 kg/hr of LP Inlet Gas at 1.08 bar and 0.1°C, kg/hr of IP Inlet Gas at 3.24 bar and 3.6 °C, kg/hr of HP Inlet Gas at 10.0 bar and 11.7°C kg/hr of Discharge Gas at 82.9 bar and 78.6°C	Isentropic efficiency: Casing 1: 0.831, Casing 2: 0.8313, Casing 3: 0.8376, Casing 4: 0.8376, Casing 5: 0.8189
24-HX-105	Compressor Aftercooler	1 (0)	60,700	GJ/hr	
24-PU-101	1st Compressor Suction KO Drum Pump	1 (1)			Normally no flow
24-PU-102	CO2 Product Pump	1 (1)	410	m3/hr with inlet at 81.0 bar and Discharge at 138.9 bar	
24-VE-101	1st Stage Compressor Suction KO Drum	1 (0)	48,192	kg/hr of LP Inlet Gas at 1.08 bar and 0.1°C	
24-VE-106	Compressor Aftercooler KO Drum	1 (0)	305,586	kg/hr of Inlet Gas at 82.6 bar and 26.7°C	
24-VE-107	CO2 Product Surge Vessel	1 (0)	305,434	kg/hr of Product CO2	
24-DR-107	Dehydration Package	1 (0)	305,586	kg/hr of CO2 containing 0.12 mole % Water Vapor	

Table A1.3 - 16: Equipment List Unit 25 - Humidification

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Equipment Number	Service	Number of Operating (spare)	Equipment Description (per Operating Train Basis)	Remarks
25-HX-100	Syngas / HP BFW Exchanger	1 (0)	53,810.0 MJ/hr Syngas preheated to 288°C	
25-PU-100	Syngas Humidifier Water Circulation Pump	1 (1)	935.0 m3/hr	
25-VE-100	Syngas Humidifier	1 (0)	15,618.0 kg moles/hr of humidified syngas with 28.5 mole % moisture	

Table A1.3 - 17: Equipment List Units 50/51 - Power Block

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Equipment Number	Service	Number of Operating (spare)	Equipment Description (per Operating Train Basis)			Remarks
50-EM-100	Gas Turbine Extraction Air Expander	1 (0)	4,745	kW		Isentropic efficiency: 0.775
50-HX-101	LP Steam Generator	1 (0)	67,600	MJ/hr		
50-HX-102	Air Trim Cooler	1 (0)	44,200	MJ/hr		
50-HX-100	N2 / HP BFW Exchanger	1 (0)	43,600	MJ/hr		
51-CO-100	Surface Condenser	1 (0)	850,000	MJ/hr		
50-FL-100	Air Filter	1 (0)	1,902,000	kg/hr Air Treated		Included with Gas Turbine
50-GG-100	Gas Turbine Generator	1 (0)	318 1392	MW at Generator Terminals °C Rotor Inlet Temperature, Pressure Ratio: 24		Steam Cooled Gas Turbine
51-HR-100	Heat Recovery Steam Generator	1 (0)	1,122,000	MJ/hr		
51-ME-101	Boiler Chemical Injection Skid	1 (0)	208,215	kg/hr of BFW		Not shown
51-PU-105	LP Boiler Feedwater Pump	1 (1)	142	m^3/hr		
51-PU-103	HP/IP Boiler Feed Water Pump	1 (1)	613	m^3/hr		
51-PU-101	Vacuum Condensate Pump	1 (1)	586	m^3/hr		
51-PU-102	Blowdown Sump Pump	1 (1)				
51-PU-104	HP BFW Circulating Pump	1 (1)	177	m^3/hr		
51-SG-100	Steam Turbine Generator	1 (0)	154	MW at Generator Terminals	Isentropic efficiency: HP Section 0.8468, IP Section 0.9158, LP Section 0.8906	

Table A1.3 - 17: Equipment List Units 50/51 - Power Block - continued

Basis: 3,274 MT/D (As Received) or 3,078 MT/D (Dry Basis) Pittsburgh No. 8 Coal

Equipment Number	Service	Number of Operating (spare)	Equipment Description (per Operating Train Basis)	Remarks
51-SU-100	Blowdown Sump	1 (0)		
51-SU-101	Water Wash Sump	1 (0)		Not shown
50-VE-100	N2 KO Drum	1 (0)	246,590 kg/hr N2	
50-VE-101	Syngas KO Drum	1 (0)	136,415 kg/hr Humid Syngas	
51-VE-101	High Pressure Steam Drum	1 (0)	307,067 kg/hr Total Steam	Included with HRSG
51-VE-102	Intermediate Pressure Steam Drum	1 (0)	63,025 kg/hr Total Steam	Included with HRSG
51-VE-103	Low Pressure Steam Drum / Deaerator	1 (0)	17,267 kg/hr Total Steam Integral Type	Included with HRSG
51-VE-104	Continuous Blowdown Drum	1 (0)	9,500 kg/hr Blowdown	
51-VE-105	Intermittent Blowdown Drum	1 (0)		
51-ME-100	Demineralizer Unit	1 (0)	208,215 kg/hr Treated Water	